Electric Load Forecast

2004/05 to 2024/25

Load Forecasting
Power Planning and Portfolio Management
Distribution Line of Business
BC Hydro

October 2004 Forecast

BC hydro

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Executive Summary

Highlights

- **Economic Outlook.** Economic growth in British Columbia is forecast to be about 2.8% in 2004 and to average about 3.0% per year for the five years from 2004 to 2008. This compares with economic growth of 2.2% in 2003 and an average of 2.2% per year for the five years from 1999 to 2003. The external economic environment continues to be positive, with consensus estimates of growth for 2004 of 2.6% for Canada, 3.0% for the United States, 4.0% for Japan and 1.5% for the Euro zone. Over the first ten years of the forecast period, average forecast GDP growth is 2.8% per year compared to 2.6% per year for the 2004 forecast. Although this is small annual difference, the cumulative effects are significant over the forecast period. The markets for BC's main commodity exports including pulp and paper, wood and wood products, copper and coal all continue to be strong. This improved outlook for the external and domestic economic environments has positive implications for electricity demand and sales in British Columbia.

- **Sales Forecast before Power Smart.** Billed sales were approximately 50,000 GWh in 2003/04. Billed sales, before incremental Power Smart impacts, are forecast to grow from about 50,000 GWh in 2003/04 to 54,100 GWh in 2008/09, to 57,700 GWh in 2014/15, and to 68,400 GWh in 2024/25. These increases represent growth rates of 1.6% over the next five years (2003/04 to 2008/09), 1.5% over the next 11 years (2003/04 to 2014/15), and 1.5% over the next 21 years of the forecast (2003/04 to 2024/25). Note that historical sales information includes the impact of Power Smart savings realised up to that year.

- **Sales Forecast with Power Smart.** Billed sales, with incremental Power Smart impacts, are forecast to grow from about 50,000 GWh in 2003/04 to 51,800 GWh in 2008/09, to 54,900 GWh in 2014/15, and to 66,000 GWh in 2024/25. These increases represent growth rates of 0.7% over the next five years (2003/04 to 2008/09), 1.0% over the next 11 years (2003/04 to 2014/15), and 1.3% over the next 21 years of the forecast (2003/04 to 2024/25).

- **Peak Demand.** Peak demand is composed of the demand for electricity at the distribution level (i.e. residential and commercial/light industrial loads), transmission customer loads (i.e. large commercial and industrial loads) plus inter-utility sales and transmission and distribution losses. Total integrated system peak was approximately 10,100 MW in 2003/04. Forecast peak before Power Smart, is expected to grow from about 10,100 MW in 2003/04 to 10,600 MW in 2008/09, to 11,450 MW in 2013/14, and to 13,200 MW in 2024/25. These increases represent growth rates of 1.6% over the next five years (2003/04 to 2008/09), 1.5% over the next 11 years (2003/04 to 2014/15), and 1.5% over the next 21 years of the forecast (2003/04 to 2024/25).

- **Rate Impacts and Elasticities.** The Reference Forecast includes the estimated impacts of the interim rate increase for the test years and then assumes that rates will be constant in real terms for the balance of the forecast period. With an assumed nominal 8.9% rate increase converted to a 2.9% rate increase after three years of 2% inflation, and with sector-specific price elasticities of less than 0.30, this means that the estimated impact on sales is less than 1%. Given the recent rate decision by the BCUC, the final rate approved will need to be confirmed and an update of the load forecast issued. The impact will likely reduce the load impact to a fraction of the 1% impact originally assumed in the Reference Forecast.

- **Gross Requirements.** Gross requirements include sales to BC Hydro's residential, commercial and industrial customers, BC Hydro's own uses and transmission and distribution losses. Gross requirements were approximately 55,200 GWh in 2003/04. Gross requirements, before incremental Power Smart impacts, are forecast to grow from about 55,200 GWh in 2003/04 to 59,180 GWh in 2008/09, to 64,900 GWh in 2013/14, and to 75,500 GWh in 2024/25. These increases represent growth rates of 1.6% over the next five years (2003/04 to 2008/09), 1.5% over the next 11 years (2003/04 to 2014/15), and 1.5% over the next 21 years of the forecast (2003/04 to 2024/25). Based on evidence for the past five years, forecast transmission losses have been reduced from 8% of billed sales to 7% of billed sales.
- **Forecast Validation.** In addition to ongoing detailed analysis of inputs and outputs, there are four primary methods of model validation. First, regression models are built for energy and peak and the results for these models are compared to those of the reference forecast. Second, the current year anchor is compared to the short-term forecast for the current year and any major variances are analyzed and corrected. Third, forecast of different recent vintages are compared and the reasons for any major changes in the forecast from year to year are examined. Fourth, drivers and growth factors are reviewed and validated in light of implied trends.
- **Factors Leading to Lower than Forecast Sales.** The main factors that could lead to lower than forecast sales include the following.
  - rapid increase in the value of the Canadian dollar could treduce growing commodity exports from BC.
  - rising interest rates in the United States and Canada could reduce North American housing demand and the demand for BC lumber.
  - a reduction in growth in China could lead to a slowing of commodity demand and commodity prices.
- **Factors Leading to Higher than Forecast Sales.** The main non-economic risks that could lead to higher than forecast sales to the forecast include assumptions about load reductions due to elasticity response to price increases applied to the forecast that do not materialize.

  The main economic risks that could lead to higher sales are as follows:
  - strengthening world demand for market pulp and energy-intensive paper grades could increase electricity demand in the pulp and paper sector
  - resolution of the softwood lumber dispute at a time when there is an ample supply of fibre in the interior of BC could increase electricity demand in the sawmilling sector.
  - strengthening business confidence could increase investment in BC leading to increased industrial and commercial demand for electricity.
  - economic spill-over of the Winter Olympics could increase investment and economic activity in British Columbia with consequent impact on electricity sales.

- **Comparison With 2003 Forecast.** The 2004 Energy Load Forecast is higher than the F2003 Energy Load Forecast for all years of the forecast period. The reasons for the increase in the forecast are as follows:

- For residential sales, the 2004 forecast is below the 2003 forecast for 2004/05 by 118 GWh because of the assumption of the impact of higher rates, but above the 2003 forecast by 437 GWh in 2013/14 and above the 2003 forecast by 829 GWh in 2023/24 because of an uplift in the anchor point for 2003/04 and an increase in the forecast number of accounts.
- For commercial sales, the 2004 forecast is above the 2003 forecast by 549 GWh for 2004/05, above the 2003 forecast by 427 GWh in 2013/14 and above the 2003 forecast by 547 GWh in 2023/24. The main reasons for the increase in forecast commercial sales are the uplift in the anchor point for 2003/04 and the increase in forecast GDP which affects floor stock.
- For industrial sales, the 2004 forecast is above the 2003 forecast by 869 GWh for 2004/05, above the 2003 forecast by 106 GWh in 2013/14 and 1138 GWh above the 2003 forecast in 2023/24. The main reasons for the increase in industrial sales are the uplift in the anchor point for 2003/04 and the increase in forecast GDP.

Introduction

BC Hydro is the third largest utility in Canada and generates nearly 80% of the electricity produced in British Columbia. The company's generating capacity is over 11,000 MW and gross requirements including losses were over 55,000 GWh in 2003/04. Sales to BC Hydro's residential, commercial, industrial and wholesale customers were over 50,000 GWh in 2003/04.

Load forecasting is central to BC Hydro's long-term planning, medium-term investment and short-term and real-time operational and forecasting activities. The BC Hydro Electric Load Forecast is produced annually and published in the fall. The forecast is based on several comprehensive engineering end-use and econometric models that use billed data up to March 31 of the relevant year as anchor information, combined with a wide variety of economic forecasts and inputs from internal, governmental and third party sources. The forecast outputs are validated through additional tests and information including time series econometric models. The primary purpose of the electric load forecast is to provide decision-making support on the questions of "where, when, why and how much" electricity is expected to be required on the BC Hydro system.

BC Hydro's load forecasting activities centre on the production of a number of term-specific and location-specific forecasts of energy sales and peak demand requirements to meet user needs for decision-support information. A variety of related products including quarterly forecast updates, monthly variance reports, inputs for the revenue forecast, load shape analysis and small area forecasts are produced to supplement the base forecasts presented in this report.

Sectors and Methodology

BC Hydro's load forecast is assembled from the following components: the residential forecast; the commercial forecast (distribution voltage and transmission voltage), the industrial forecast (distribution voltage and transmission voltage) and the peak forecast. A variety of engineering and econometric models are used to produce the forecast. These specific forecast methods are based on their predictive value and their ability to most appropriately meet the needs of users.

Residential Forecast

Of the three customer classes, residential, commercial, and industrial, the residential sector is the most stable. Growth in the number of residential accounts is about the same as growth in population, which is currently about 1.2%. After many years of growth in use per account, growth in use per account is forecast to moderate, growing at less than 1% over the entire forecast period. Key features of the residential forecast include the following:

- Electricity Use - BC Hydro's residential sector currently consumes about 33% of BC Hydro's total annual billed sales. This electricity is used to provide a range of services including space heating, water heating, refrigeration, and miscellaneous plug-in load which includes computer equipment and home entertainment systems.
- Drivers - The drivers of the residential forecast are number of accounts and average annual use per account. Number of accounts is driven by estimates of housing starts which in turn is driven by population growth and the trend in people per account. With growth expected in both number of accounts and use per account, growth in sales is forecast to average 1.7 % over the entire forecast period.
- Trends - At the end of 2007/08, the new forecast for number of accounts is 1,569,000, which is 6,400 or 0.4% above the previous forecast. At the end of 2023/24, the new forecast for number of accounts is 2,006,000, which is 90,000 or 4.7% above the previous forecast. Based on the application of elasticity of use assumptions, BC Hydro's recent rate request is expected to lower use rate by about 1% in the short term, but over the long term, use rate is not expected to change significantly.
- Forecast - Billed residential sales were approximately 15,900 GWh in 2003/04. Forecast sales to residential customers, before Power Smart, are expected to grow from about 15,900 GWh in 2003/04 to 17,200 GWh in 2008/09, to 19,000 GWh in 2013/14, and to 22,800 GWh in 2024/25. These increases represent growth rates of 1.6% over the next five years (2003/04 to 2008/09), 1.8% over the next 11 years (2003/04 to 2014/15), and 1.7% over the next 21 years of the forecast (2003/04 to 2024/25).

Commercial Forecast

BC Hydro's commercial sector encompasses a wide a variety of commercial and publicly provided services. It includes a very diverse set of BC Hydro customers who operate a wide range of facilities such as office buildings, retail stores, institutions (i.e., hospitals and schools) and transportation infrastructure. The remainder of the sector is comprised of facilities (non-buildings) such as transportation infrastructure and public utilities. Key features of the commercial forecast include the following:

- Electricity Use– BC Hydro's commercial sector currently consumes 28% of BC Hydro's total annual billed sales This electricity is used to provide a range of services (often called end-uses) such as lighting, ventilation, heating, cooling, refrigeration, hot water, etc. These needs vary considerably between the different types of buildings.
- Drivers – Within the building sector, floor stock and end use are assumed to drive consumption. However because consumption in the commercial sector is tied so closely with economic activity in the province, there is a strong relationship between consumption and economic indicators such as the provincial GDP (Gross Domestic Product) and employment rates. As a result, future economic

trends are a good indicator of future electricity consumption in the commercial sector.

- Trends – Electricity consumption of the commercial sector can vary considerably from year to year reflecting the level of activity in BC's service sector. Sales to BC Hydro's commercial sector in 2003/04 grew by 3.1% reflecting the strong performance of the BC economy. Growth consistent with a strong economy is expected to continue however at a reduced level.
- Forecast - Billed commercial sales were approximately 14,200 GWh in 2003/04. Commercial sales, before incremental Power Smart impacts, are forecast to grow from about 14,200 GWh in 2003/04 to 15,600 GWh in 2008/09, to 17,200 GWh in 2013/14, and to 20,800 GWh in 2024/25. These increases represent growth rates of 2.0% over the next five years (2003/04 to 2008/09), 1.9% over the next 11 years (2003/04 to 2014/15), and 1.9% over the next 21 years of the forecast (2003/04 to 2024/25).

Industrial Forecast

BC Hydro's industrial sector is concentrated in a limited number of industries, the most important of which are pulp and paper, wood products, chemicals, metal mining and coal mining. The remaining industrial load is made up of a large number of small and medium sized manufacturing establishments. Key features of the industrial forecast include the following:

- Electricity Use - BC Hydro's industrial sector currently consumes some 40% of BC Hydro's total annual billed sales This electricity is used to provide a range of services including fans, pumps, compression, conveyance, processes such as cutting, grinding, stamping and welding and electrolysis.
- Drivers – As in the case of the commercial sector, industrial electricity consumption is tied closely with the level of economic activity in the province. In other words, there is a strong relationship between industrial electricity consumption and provincial Gross Domestic Product. Future economic trends are a good indicator of future electricity consumption in the industrial sector.
- Trends - Electricity consumption in the industrial sector is quite volatile, driven substantially by economic conditions in the United States, China and Japan that affect commodity markets. Export sales to these three countries are a key determinant of domestic industrial output and of the industrial demand for electricity. Trends for sales to these markets are positive.
- Forecast - Billed industrial sales were approximately 18,700 GWh in 2003/04. Forecast sales to industrial customers, before Power Smart, are expected to grow from about18,700 GWh in 2003/04 to 19,800 GWh in 2008/09, to 20,900 GWh in 2013/14, and to 24,700 GWh in 2024/25. These increases represent growth rates of 1.2% over the next five years (2003/04 to 2008/09), 0.8% over the next 11 years (2003/04 to 2014/15), and 1.0% over the next 21 years of the forecast (2003/04 to 2024/25).

Gross Requirements.

Gross requirements include sales to BC Hydro's residential, commercial and industrial customers, BC Hydro's own uses and transmission and distribution losses. Gross requirements were approximately 55,200 GWh in 2003/04. Gross requirements, before incremental Power Smart impacts, are forecast to grow from about 55,200 GWh in 2003/04 to 59,180 GWh in 2008/09, to 64,900 GWh in 2013/14,

and to 75,500 GWh in 2024/25. These increases represent growth rates of 1.6% over the next five years (2003/04 to 2008/09), 1.5% over the next 11 years (2003/04 to 2014/15), and 1.5% over the next 21 years of the forecast (2003/04 to 2024/25). Transmission losses are significantly influenced by the origin and by the destination of the load being transmitted. Based on evidence for the past five years, forecast transmission losses have been reduced from 8% of billed sales to 7% of billed sales, reducing the growth in total gross requirements compared to the 2003 forecast.

Peak Demand

Peak demand is composed of the demand for electricity at the distribution level (i.e. residential and commercial/light industrial loads), transmission customer loads (i.e. large commercial and industrial loads) plus inter-utility sales and transmission and distribution losses. Key features of the peak forecast include the following:

- Electricity Use – Peak demand is forecast as the maximum expected one-hour demand during the year. For BC Hydro's load, this peak demand occurs in winter with the peak driven in particular by the residential space heating load. BC Hydro defines this one-hour peak event on the basis of expected demand on the average coldest day of the year (design day temperature has been changed from –6.8 degrees Celsius to –5.3 degrees Celsius).
- Drivers – Key drivers of electricity peak at the regional level include the level of economic activity, number of accounts, use rate per account, and the pattern of winter day cold temperatures. At the system level, the coincidence of regional peaks with overall system peak is also a determinant of the system peak.
- Trends – Since peak demand is defined as an extreme event of expected one hour load on the average coldest day of the year, it is more volatile than electricity sales. This volatility can mask trends in peak demand, as peak can move up or down substantially from year to year in response to a few days of extreme winter weather. Nevertheless, the long-term trend in peak is strongly upward.
- Forecast – Total integrated system peak was approximately 10,100 MW in 2003/04. Forecast peak before Power Smart, is expected to grow from about 10,100 MW in 2003/04 to 10,600 MW in 2008/09, to 11,450 MW in 2013/14, and to 13,200 MW in 2024/25. These increases represent growth rates of 1.6% over the next five years (2003/04 to 2008/09), 1.5% over the next 11 years (2003/04 to 2014/15), and 1.5% over the next 21 years of the forecast (2003/04 to 2024/25).

Energy and Peak Forecast Before Power Smart

Table 1 and Table 2 provides a summary of historical and forecast sales and peak for selected years, both before and with Power Smart.

Table 1. Energy and Peak Forecast Before Power Smart for Selected Years

	Residen-tial (GWh)	Commer-cial (GWh)	Industrial (GWh)	Total Domestic Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated System Peak * (MW)
1998/99	13,972	12,814	18,077	45,513	50,897	9,026
2003/04	15,899	14,151	18,725	49,960	55,187	10,103 (9,754)
2008/09	17,234	15,642	19,918	54,070	59,754	10,645
2014/15	19,376	17,471	20,426	58,671	64,858	11,499
2024/25	22,828	20,834	23,123	68,352	75,530	13,193
Growth Rates[1]						
5 years: 98/99 to 03/04	2.6%	2.0%	0.7%	1.9%	1.6%	2.3% (1.6%)
5 years: 03/04 to 08/09	1.6%	2.0%	1.2%	1.6%	1.6%	1.6% (1.8%)
11 years: 03/04 to 14/15	1.8%	1.9%	0.8%	1.5%	1.5%	1.5% (1.5%)
21 years: 03/04 to 24/25	1.7%	1.9%	1.0%	1.5%	1.5%	1.5% (1.4%)

*Values shown in brackets are based on weather normalized actuals

Table 2. Energy and Peak Forecast After Power Smart for Selected Years

	Residen-tial (GWh)	Commer--cial (GWh)	Industrial (GWh)	Total Domestic Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated System Peak* (MW)
1998/99	13,972	12,814	18,077	45,513	50,897	9,026
2003/04	15,899	14,151	18,725	49,960	55,187	10,103 (9,754)
2008/09	16,842	15,150	18,518	51,786	57,268	10,296
2014/15	18,812	16,831	18,794	55,835	61,767	11,064
2024/25	22,273	20,217	21,910	65,967	72,923	12,822
Growth Rates						
5 years: 98/99 to 03/04	2.6%	2.0%	0.7%	1.9%	1.6%	2.3% (1.6%)
5 years: 03/04 to 08/09	1.2%	1.4%	-0.2%	0.7%	0.7%	0.7% (1.1%)
11 years: 03/04 to 14/15	1.5%	1.6%	0.0%	1.0%	1.0%	1.0% (1.2%)
21 years: 03/04 to 24/25	1.6%	1.7%	0.8%	1.3%	1.2%	1.3% (1.3)

* Values shown in brackets are based on weather normalized actuals

[1] Unless otherwise noted, growth rates are calculated as annual compound growth rates

Sensitivity Analysis and Risks

BC Hydro's load forecast is sensitive to a number of variables including weather, economic conditions, price, etc. BC Hydro's analysis has looked specifically at the sensitivity of the load to changes in the economy (GDP) and price of electricity. In addition, a composite sensitivity analysis (Monte Carlo study) has been completed to look at the sensitivity of the load to a combination of five non-weather causal factors that affect the forecast.

This composite sensitivity analysis is used to derive an uncertainty band around the reference forecast. Five major causal factors were analyzed to determine the range of forecasts that would have an 80 per cent confidence level encompassing the reference forecast. The high, reference and low growth rates over the forecast period were projected to be about 2.0 per cent, 1.6 per cent and 1.2 per cent respectively in Total Gross Requirements, before Power Smart over the 21 year forecast period.

Beyond the general economic risk of higher or lower than economic growth assumptions materializing, a significant risk to the industrial forecast pertains to discrete one time changes in sales to the base metal mining and pulp and paper sectors. Specifically, risks not represented in the forecast relate to large one-time additions or contractions of load as a result of new investment, strikes or closure of major facilities. Because it is difficult to assess the likelihood of these events, the approach has been to relate the industrial load to GDP rather than attempt to forecast these individual discrete events. However, as it relates to one large mining customer, based on public statements of intent to decommission beginning in 2007/08 made earlier in the year, BC Hydro has reduced this load to reflect this discrete event.

The main downside risks to the forecast load include the following. First, rapid increase in the value of the Canadian dollar could reduce growing commodity exports from BC. Second, rising interest rates in the United States and Canada could reduce North American housing demand and the demand for BC lumber. Third, reduction in growth in China could lead to a slowing of commodity demand and commodity prices.

The main upside risks to the forecast load include the following. First, strengthening world demand for market pulp and energy-intensive paper grades could increase electricity demand in the pulp and paper sector. Second, resolution of the softwood lumber dispute at a time when there is an ample supply of fibre in the interior of BC could increase electricity demand in the sawmilling sector. Third, strengthening business confidence could increase investment in BC leading to increased industrial and commercial demand for electricity.

The main non-economic risks to the forecast include assumptions about load reductions due to elasticity response to price increases applied to the forecast that do not materialize.

1 Introduction

1.1. Background and Context

BC Hydro is the third largest electric utility in Canada and generates nearly 80 per cent of the electricity produced in British Columbia. Generating capacity is over 11,000 MW, with about 90 per cent of this capacity consisting of hydro-electric generation and the balance thermal generation. The remainder of the provincial electric generation capacity includes Alcan's Kemano facility, Fortis BC's plants, industry self-generation, particularly in the forest products sector, independent power producers, and small, off-grid installations, particularly in the northern part of British Columbia. Gross requirements, including losses were some 55,187 GWh in 2003/04, while firm sales were some 50,273 GWh in 2003/04.

The BC Hydro Electric Load Forecast is produced annually and published in the fall. The forecast is based on comprehensive model runs that use billed data up to March 31 of the relevant year as anchor information, combined with a wide variety of forecasts and inputs from internal, governmental and third party sources. In addition, because of the timing of forecast release, this year's forecast has been adjusted to reflect actual sales through September 2004. The primary purpose of the electric load forecast is to provide decision-making support on the questions of "where, when, why and how much" electricity is expected to be required on the BC Hydro system.

The forecast includes only domestic load and firm exports. The forecast does not take into account the possibility of additional sales to other utilities in the event of an excess water year generating surplus supply, nor does it reflect the net effects of the time-shifting activities that are recorded as sales activities by Powerex.

1.2. Role of Forecasting at BC Hydro

Load forecasting is central to BC Hydro's long-term planning, medium-term investment and short- and real-term operational and reporting activities. As such, BC Hydro's load forecasting activities centre on the production of a number of term-specific and location-specific forecasts of energy sales and peak demand requirements to meet user needs for decision support information. A variety of related products including quarterly forecast updates, monthly variance reports, inputs for the revenue forecast, load shape analysis and small area forecasts are produced to supplement the base forecasts. Additionally, analytical, statistical and modelling support for a number of special or one time projects, including the Vancouver Island Call for Tender, the NITS Application, Cost of New Energy Supply, Rate Design and the Integrated Electricity Plan, are also provided.

Forecast requirements for electric utilities are changing in response to a number of changes in the industry. These changes include:

- Increased risks as the system operates closer to capacity, increasing need for more frequent, shorter-term and risk-based forecasting at the regional, area or district level;
- Future uncertainty, resulting in more need for stress testing, and a focus on risk/sensitivity analysis;

- A shift from a previous focus on 20-year energy and peak forecasts for an integrated system, updated annually, to an increasing need for more frequent and shorter-term forecasts at the regional, area or district level;
- Focus on understanding and meeting the needs of users; and
- Increased interest on the part of the regulator and other stakeholders, reinforcing a need to ensure methods are transparent, consistent and defensible in regulatory context.

The main users and uses of forecast products include the following:

- Generation: real-time load forecast, generating facility station dispatch and system operations;
- Rates: rate design and rate structure;
- Distribution: revenue forecasting, portfolio forecasting, distribution planning and investment;
- Transmission: transmission planning and investment;
- Powerex: resource availability for trade;
- Corporate:financial forecasts, service plan and budget reports; and
- BC Utilities Commission: demonstrating obligation to serve and prudence regarding expenditure and needs.

The key focus for the current year is to ensure that the forecast function is evolving appropriately in response to these trends and to complete implementation of the Forecast Renewal Project. The Forecast Renewal Project involves building new forecasting models that are more accurate, transparent and easier to use than the existing models.

1.3. Overview

The sections of the Electric Load Forecast are as follows.

- Section 1. Introduction
- Section 2. Regulatory Background
- Section 3. Forecast Process and Methodologies
- Section 4. Forecast Drivers, Data Sources and Assumptions
- Section 5. Reference Forecast
- Section 6. Comparison Between 2003/04 and 2004/05 Forecasts
- Section 7. Sensitivity Analysis
- Section 8. Residential Forecast
- Section 9. Commercial Forecast
- Section 10. Industrial Forecast
- Section 11. Peak Forecast
- Section 12. Power Smart and the Conservation Potential Review

2 Regulatory Background

In November 2002, the Government of British Columbia released its new energy policy, Energy for our Future: A Plan for B.C. Following the release of the energy policy, the Utilities Commission Act was amended, in part, to provide a mandate consistent with the new energy policy. In particular, the amendments clarified the regulatory role of the British Columbia Utilities Commission (BCUC) with respect to the planning requirements of utilities.

In July 2003, the BCUC issued draft resource planning guidelines. Section III (2) of the draft guidelines considers the development of gross demand forecasts (before considering the effect of demand-side management programs) and states:

> "In making a demand forecast, it is necessary to distinguish between demographic, social, economic and technological factors unaffected by utility actions, and those actions that the utility can take to influence demand, (e.g. rates, DSM programs). The latter actions should not be reflected in the utility's gross demand forecasts. More than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered to be more likely than others..."

In its decision on the Vancouver Island Generation Project of September 8, 2003, the BCUC provided a number of specific decisions relevant to the load forecast. These decisions and the actions taken in response were summarized in Table 2.1 of the 2003 Electricity Load Forecast.

In its decision on the Regulatory Requirements Application of October 29, 2004, the BCUC found that the "Electric Load Forecast 2003/04 to 2023/24 documenting BC Hydro's forecasting approach informative and responsive to the comments made in the September 2003 BCUC Decision on the VIGP CPCN application". In addition in its decision, the BCUC provided a number of comments pertaining to the Load Forecast. These comments and actions currently underway in response to these comments are summarized in Table 2.1.

Table 2.1. B.C. Utilities Commission Comments and Actions

Comment	Action
1. Streamline the load forecasting function.	1. New econometric based forecasting models are being built to simplify forecasting for the residential and commercial sectors
2. Prepare more rigorous short-term forecasting	2. A series of short-term models are being developed to forecast quarterly electricity consumption by rate class
3. Include impacts of the rate increase in the Reference Load Forecast	3. Rate impacts have been included in the 2004 Reference Load Forecast, based on rate increase requested; a revision will need to be made to revise the load forecast for the approved rate increase once it is known.
4. Deal with seasonal bias in inputs	4. Use quarterly key drivers for the short-term forecast
5. Load Displacement Projects should be considered as supply side alternatives and not included as part fo the Power Smart 10-Year Plan	5. Revise the with Power Smart Load Forecast as revised Power Smart savings forecasts, excluding Load Displacement Projects, are available

3 Forecast Process and Methodologies

There are a number of key components to the load and sales forecast: the residential forecast; the commercial forecast (distribution voltage and transmission voltage); the industrial forecast (distribution voltage and transmission voltage); and the peak forecast. This section briefly reviews the key algorithms used for each of these components.

3.1. Residential Forecast Methodology

The residential energy forecast is determined by forecasting the number of accounts times rate of use based on the following expression:

(3.1) $RES = \Sigma_k \Sigma_j \Sigma_i R_{ijk} * RUR_{ijk}$,

where:

- RES is residential consumption;
- R is the number of residential accounts;
- RUR is the residential use rate;
- i indexes 20 appliances (space heating, space cooling, water heater, refrigerator, freezer, clothes washer, clothes dryer, dishwasher, range, lighting and so on);
- j indexes four housing types (single/duplex, row, apartment and other); and
- k indexes four regions (Lower Mainland, Northern Region, South Interior and Vancouver Island).

The residential energy forecast is determined by forecasting the number of accounts multiplied by the rate of use. The forecast in the growth of the number of residential accounts is based on a forecast of housing starts provided by a third party . The number of residential accounts is then the current number of residential accounts plus the additional accounts added each eyar.

Use rates are forecast from appliance saturation rates and unit energy consumption per end use (as well as their trends) to determine the average use rate by dwelling type and region and changes in these rates over time. Appliance saturation rates and unit energy consumption come from the Residential End-Use Energy Planning System model (REEPS) as updated using the Residential End Use Survey (REUS) and the Conservation Potential Review (CPR).

3.2. Commercial Forecast Methodology

The commercial distribution energy forecast for buildings (about four-fifths of the commercial load) is determined by forecasting floor stock times rate of use based on the following expression:

(3.2) $COMDB = \Sigma_k \Sigma_j \Sigma_i STOCK_{ijk} * SHARE_{ijk} * EUI_{ijk}$

where:

- COMDB is commercial distribution voltage building consumption;
- STOCK is segment floor stock;
- SHARE is the share of stock with a given end use (these are essentially fuel shares);
- EUI is end use intensity for a given end use;
- i indexes existing and new buildings;
- j indexes 10 end uses; and
- k indexes 13 building types.

Shares of end-use stock come from the Commercial End-Use Energy Planning System (COMMEND) and are updated from the Conservation Potential Review (CPR).

The commercial distribution energy forecast for non-buildings, which includes transportation, communications and utilities (about one-fifth of the commercial load), is based on the following regressions:

(3.3) COMDNB = F(GDP, EMP, POP)

where:

- COMDNB is commercial distribution voltage non-building consumption;
- GDP is real provincial GDP;
- EMP is provincial employment; and
- POP is provincial population.

The commercial transmission energy forecast is based on the following expression:

(3.4) $COMT = \Sigma_j BASE_j*(1 + EXP_j)$

where:

- COMT is commercial transmission energy consumption;
- BASE is base year consumption for account j; and
- EXP is the expected impact of changes in facility size such as expansions or changes in usage rates by reference to detailed customer-by-customer projections, which are validated against other growth indices, and combined with projected trends in energy use.

3.3. Industrial Forecast Methodology

The industrial distribution energy forecast is based on the following expression:

(3.5) $INDC = \alpha_j + \beta_j * GDP$

where:

- INDC is industrial distribution energy;
- α_j and β_j are the regression coefficients from a time series regression for industry j of electricity sales on provincial GDP.

The industrial transmission voltage energy forecast is based on the following expression:

(3.6) $INDD = \alpha_j + \beta_j * GDP$

where:

- INDD is industrial energy consumption for transmission voltage customers.

A modified version is also estimated that incorporates the impacts of industrial strikes:

(3.7) $INDD_t = \alpha + \beta * GDP_t + \chi *$Dummy variable for strike years.

3.4. Peak Forecast Methodology

It is convenient to think of the peak or demand forecast as built up of four stages, each with several steps. First, substation peak in MVA non-coincident[2]; second, area peak in MVA non-coincident; third, region peak in MW on a region coincident basis; and, fourth, system peak in MW on a system coincident basis.

The substation peak forecast is first built up in several steps: (a) actual and normalized peak loads by substation/area; (b) area substation peak forecast guidelines are developed from an econometric model; (c) an 11-year substation forecast; and (d) the substation and guideline peak forecast are averaged together.

The first step is analysis of last year's substation peak using the following:

(3.8) $KVA = \alpha + \beta * min$

where:

- KVA is the weekly peak load; and
- min is the minimum temperature for the coldest day in the week.

[2] Non-coincident refers to use of a coincidence factor that is a ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

Using the estimated regression coefficients, the weather-normalized peak is then calculated based on the design day temperature for that substation:

(3.9) $NKVA = \alpha + \beta^{*}designmin$

where:

- NKVA is weather-normalized peak; and
- designmin is the design temperature for the substation.

The second step is the 11-year substation guideline (econometric model):

(3.10) $SK_{it} = [\alpha_1 SFDHTG + \alpha_2 SFDNON + \alpha_3 MULTHTG + \alpha_4 MULNON + \alpha_5 U35E + \alpha_6 O35E]$

where:

- SFDHTG is the number of single-family electrically heated homes;
- SFDNON is the number of single-family non-electrically heated homes;
- MULTHTG is the number of multi-family electrically heated homes;
- MULTNON is the number of multi-family non-electrically heated homes;
- U35E is annual energy consumption under 35 kW;
- O35E is annual energy consumption over 35kW;
- the coefficients $\alpha 1$, $\alpha 2$, $\alpha 3$, and $\alpha 4$ are kW contribution to the distribution peak per dwelling in area i, for the four dwelling types under normal temperature conditions; and
- the coefficients, $\alpha 5$ and $\alpha 6$ represent the increase in peak demand due to a one-kWh increase in the General Under 35 and Over 35 kW energy consumption.

As the third step, a longer-term (11-year) substation forecast is prepared based on trends in substation growth, load transfers between substations and large substation load additions. The fourth step is calculation of the blend/average of the long-term substation peak forecast and the peak guideline forecast for area i as:

(3.11) $PK_{it} = \Sigma_{it} SK_{it}$

This calculation is done for 15 areas.

The regional peak is forecast using:

(3.12) $RPK_{jt} = \Sigma_j [PK_{it}{}^{*}DCF_j{}^{*}PF_j{}^{*}(1+DL) + TP_j{}^{*}TCF_j{}^{*}PF_j + WP_j{}^{*}WCF_j]$

where:

- DCF is the distribution peak coincidence factor;
- PF is the power factor;
- DL is the distribution loss factor;
- TP is the transmission peak;
- TCF is the transmission coincident factor;
- WP is the wholesale peak;
- WCF is the wholesale coincident factor.

Finally, system peak is the sum of coincidence-adjusted regional peaks and includes transmission losses:

(3.13) $SPK = (1 + TL)^{*}\Sigma_j RPK_{jt} {}^{*}SCF_j$

where:

- TL is the transmission loss factor; and
- SCF is the system coincidence factor for each of the four regions.

3.5. Validation

In addition to ongoing detailed analysis of inputs and outputs, there are four primary methods of model validation:

- First, regression models are built for energy and peak and the results for these models are compared to those of the reference forecast.
- Second, the current year anchor is compared to the short-term forecast for the current year and any major variances are analysed and corrected.
- Third, forecast of different recent vintages are compared and the reasons for any major changes in the forecast from year from year to year are examined.
- Fourth, drivers and growth factors are reviewed and validated in light of implied trends.

4 Forecast Drivers, Data Sources and Assumptions

4.1. Forecast Drivers

Table 4.1 provides an overview of the key drivers for the reference forecast. For each forecast segment, this exhibit includes the activity variables, the use rate variables and the summary data sources.

The activity variable is a variable that drives the scale of electricity use. The use rate is a variable that measures the intensity of electricity use.

Table 4.1. Key Forecast Drivers

	Activity	Use Rate	Data Sources
1. Residential Forecast	• Number of residential accounts by housing type, heating type, region	• Consumption per account based on Residential End-Use Energy Planning System (REEPS)	• Current number of accounts as base • Housing starts • Appliance saturation rates from Residential End Use Survey (REUS)
2. Commercial Distribution Forecast	• Floor stock by building type and by existing and new buildings	• Fuel share • Consumption per square foot based on Commercial End-Use Energy Planning System (COMMEND)	• Floor stock forecasts • End use saturation rates and intensities from Commercial End Use Survey (CEUS) with updates from Conservation Potential Review (CPR).
3. Commercial Transmission Forecast	• Number of facilities	• Current consumption	• Billing data • GDP forecast
4. Industrial Distribution Forecast	• GDP (based on regression modelling)	• Current consumption	• Billing data • GDP forecast
5. Industrial Transmission Forecast	• GDP (based on regression modelling)	• Current consumption adjusted for expansions, contractions, closures	• Industrial billing data for industrial transmission customers • GDP forecasts
6. Non-Integrated Forecast	• Number of accounts	• Consumption per account (based on REEPS)	• Current number of accounts as base • Local conditions for short term (first four years) • Population forecast for longer term (next 17 years) • Appliance saturation rates from REUS
7. Peak Forecast	• Number of accounts by type • Sales to general sector • Industrial Activity and GDP	• Residential – kW/Account • General– kW/kWh • Transmission – peak demand (kW) from billing data	• Previous years peak by substation, region and weather data for normalization • Customer billing data • Economic and demographic forecasts

4.2. Growth Rates

Table 4.2 provides a summary of assumptions on key growth rates for the reference forecast. Growth rates are shown for account growth, real GDP, commercial buildings floor stock and employment. Unless otherwise noted, all growth rates are calculated as average annual compound growth rates.

For GDP, three sources have been used to generate the weighted average shown in the table. The average is heavily weighted to the BC Ministry of Finance Forecast in the first four years and then to third party sources for values

further out (see Table 4.3). Actual data is shown for 1998 to 2003 and forecast data is shown for 2004 to 2023. Three features of this data are worth noting.

- First, based on third party information modest rates of account growth are assumed for the forecast period, which acts as a constraint on growth of residential and commercial energy consumption.
- Second, although the forecast assumes reasonably smooth future growth in GDP, the B.C. economy in recent years has been subject to significant external shocks that have led to quite uneven growth rates. This is a significant source of uncertainty for the load forecast.
- Third, the growth assumptions used here do not take into account the possibility that improvements in the investment climate in British Columbia could lead to further increases in population, number of residential accounts and GDP above the levels forecast.

Table 4.2. Growth Assumptions

	Accounts (%)	Real GDP Weighted (%)	Commercial Floor Stock (%)	Employment (%)
Actual				
1998	0.8	1.3	2.2	0.1
1999	0.9	2.8	2.2	1.9
2000	0.9	4.3	2.1	2.3
2001	0.9	-0.2	2.2	-0.4
2002	1.3	1.8	1.9	1.6
2003	1.5	2.2	2.5	2.5
Forecast				
2004	1.6	2.8	2.4	1.8
2005	1.7	3.1	2.4	1.8
2006	1.8	3.1	2.8	1.9
2007	1.2	3.0	2.8	1.9
2008	1.3	2.9	2.9	1.9
2009	1.3	2.8	2.9	2.5
2010	1.4	3.2	2.9	3.2
2011	1.4	2.4	2.6	1.7
2012	1.3	2.4	2.6	1.6
2013	1.4	2.4	2.5	1.7
2014	1.4	2.5	2.5	1.7
2015	1.4	2.5	2.5	1.7
2016	1.3	2.4	2.3	1.7
2017	1.2	2.4	2.3	1.7
2018	1.2	2.4	2.3	1.7
2019	1.3	2.3	2.3	1.7
2020	1.1	2.3	2.3	1.7
2021	1.1	2.3	2.3	1.7
2022	1.2	2.3	2.3	1.7
2023	1.2	2.3	2.3	2.7
2024	1.1	2.3	2.3	1.7

Notes: See Data Sources, Table 4.3.

Information on the sources and the uses of the growth assumptions is shown in Table 4.3. For each key driving variable, this exhibit shows those applications where the variable is used, the time period(s) for which the variable is used and the detailed data sources.

4.3. Data Sources

Table 4.3. Data Sources and Uses for Growth Assumptions

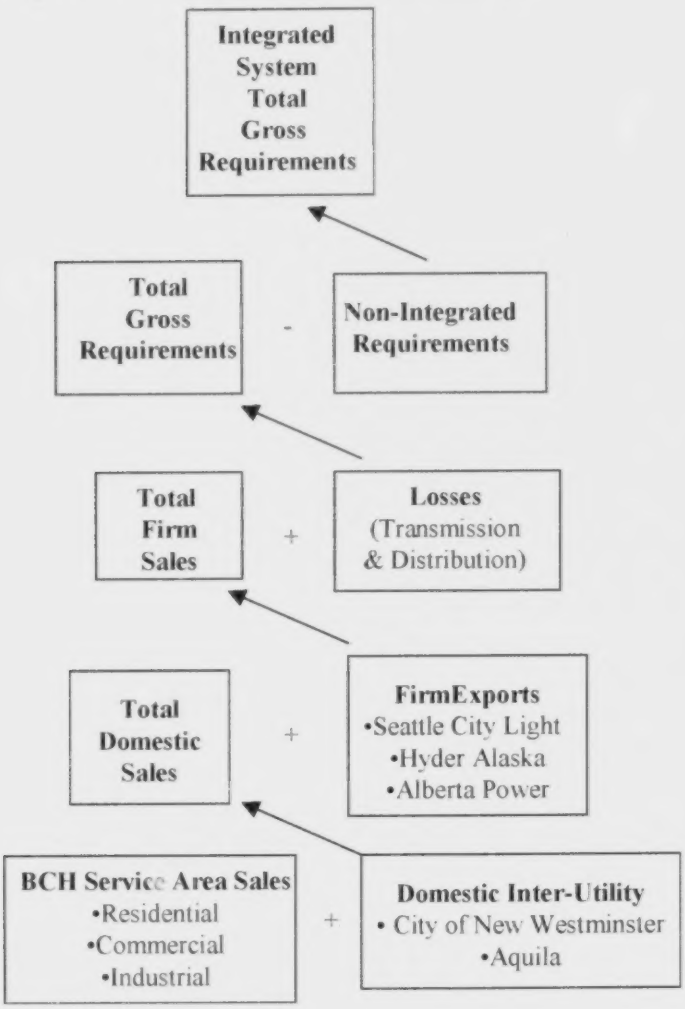
Variable	Application	Period	Source
Population	• Used as a check on account growth	• 2004-2024	• B.C. Statistics, B.C. Population Forecast, June 2004
GDP (Gov)*	• Industrial energy forecast	• 2004-2007	• B.C. Ministry of Finance, First Quarterly Report 2004/05, September 2004
GDP (third party)	• Industrial energy forecast	• 2004-2024	• R.A Malatest, July 2004
GDP (DOE)	• Industrial energy forecast	• 2008-2024	• B.C. share based on Canadian GDP forecast, USA Department of Energy, Annual Energy Outlook 2004
GDP (weighted)	• Industrial energy forecast	• 2004-2024	• Weighted average of Malatest and government sources
Commercial Floor Stock	• Commercial building energy	• 2004-2024	• R.A Malatest, July 2004
Housing Starts and Account Growth	• Residential energy forecast	• 2004-2024	• R.A Malatest, July 2004
Employment	• Number of general under 35 kW accounts for peak	• 2004-2024	• B.C. Ministry of Finance, First Quarterly Report 2004/05, September 2004
	• Number of general over 35 kW accounts for peak	• 2004-2024	• B.C. Ministry of Finance, First Quarterly Report 2004/05, September 2004

*GDP forecast are available from the BC Provincial government for only the first five years of the forecast period thus requiring use of other sources.

5 Reference Forecast

The Reference Forecast is built up of a number of elements. Figure 5.1 summarizes the aggregation of the different elements of BC Hydro's reference energy forecast.

Figure 5.1. BC Hydro Load Forecast Build-up



5.1. Reference Forecast Before Power Smart

Table 5.1 provides a summary of historical sales and peaks and the reference forecast before Power Smart, that is, before considering the effects of BC Hydro's demand-side management program (See Sections 8, 9 and 10 for the individual sector forecasts). BC Hydro's total domestic sales before Power

Smart include residential, commercial and industrial sales for the BC Hydro service area as well as sales to New Westminster and Fortis BC. BC Hydro's total domestic sales before Power Smart are expected to grow from 49,960 GWh in 2003/04 to 68,352 GWh in 2024/25. BC Hydro's total gross requirements include total domestic sales, firm exports, losses and non-integrated areas. BC Hydro's total gross requirements before Power Smart are expected to grow from 55,187 GWh in 2003/4 to 75,530 GWh in 2024/25.

Growth rates of sales vary significantly by sector but within a given sector are fairly consistent over time. For the residential sector, the growth rates of sales before Power Smart are 1.6 per cent for the five years from 2003/04 to 2008/09; 1.8 per cent for the 11 years from 2003/04 to 2014/15; and 1.7 per cent in the 21 years of the forecast 2003/04 to 2024/25.

For the commercial sector, the growth rates of sales before Power Smart are 2.0 per cent for the five years from 2003/04 to 2008/09; 1.9 per cent for the 11 years from 2003/04 to 2014/15; and 1.9 per cent in the 21 years of the forecast, 2003/04 to 2024/25.

For the industrial sector, the growth rates of sales before Power Smart are 1.2 per cent for the five years from 2003/04 to 2008/09; 0.8 per cent for the 11 years from 2003/04 to 2014/15; and 1.0 per cent in the 21 years of the forecast, 2003/04 to 2024/25.

For total gross requirements, the growth rates of sales before Power Smart are 1.6 per cent for the five years from 2003/04 to 2008/09; 1.5 per cent for the 11 years from 2003/04 to 2014/15; and 1.5 per cent in the 21 years of the forecast, 2003/04 to 2024/25.

BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) before Power Smart is expected to grow from 10,103 MW (9,754 MW weather normalized) in 2003/04 to 13,193 MW in 2024/25. The five-year growth rate from 2003/04 to 2008/09 is 1.1 per cent (1.8 per cent weather normalized). The 11-year growth rate from 2003/04 to 2014/15 is 1.2 per cent (1.5 per cent weather normalized). The 21-year growth rate from 2003/043 to 2024/05 is 1.3 per cent (1.4 per cent weather normalized).

Table A8.1 in Appendix 8 provides additional details of the 2004 forecast before Power Smart.

Table 5.1. Reference Forecast Before Power Smart

	Residen-tial (GWh)	Commer-cial (GWh)	Indust-rial (GWh)	Total Domestic Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated Sys. Peak* (MW)
Actual (not weather-normalized)						
1997/98	13,802	12,466	16,339	43,072	48,342	8,566 (8,672)
1998/99	13,972	12,814	18,077	45,513	50,897	9,026
1999/00	14,572	13,176	17,890	46,376	51,534	8,646
2000/01	14,573	13,654	18,579	47,891	52,978	9,320
2001/02	15,090	13,583	17,739	47,473	52,567	9,003
2002/03	15,287	13,729	18,596	48,685	53,298	8,824
2003/04	15,899	14,151	18,725	49,960	55,187	10,103* (9,754)
Forecast (Residential Energy and System Peak forecasts assume "normal weather")						
2004/05	15,844	14,521	19,250	50,811	56,182	10,044
2005/06	16,220	14,731	19,473	51,551	56,973	10,136
2006/07	16,515	15,049	19,623	52,338	57,842	10,297
2007/08	16,880	15,316	19,772	53,175	58,768	10,451
2008/09	17,234	15,642	19,918	54,070	59,754	10,645
2009/10	17,601	15,983	19,612	54,491	60,235	10,771
2010/11	17,964	16,333	19,899	55,510	61,359	10,952
2011/12	18,326	16,581	19,711	55,952	61,862	11,052
2012/13	18,684	16,879	19,939	56,856	62,857	11,215
2013/14	19,033	17,156	20,176	57,740	63,831	11,360
2014/15	19,376	17,471	20,426	58,671	64,858	11,499
2015/16	19,715	17,777	20,682	59,593	65,876	11,655
2016/17	20,059	18,077	20,936	60,510	66,885	11,814
2017/18	20,405	18,382	21,193	61,436	67,906	11,979
2018/19	20,754	18,678	21,459	62,365	68,929	12,146
2019/20	21,100	19,022	21,729	63,341	70,008	12,314
2020/21	21,442	19,373	21,996	64,317	71,082	12,475
2021/22	21,785	19,731	22,268	65,307	72,173	12,636
2022/23	22,133	20,090	22,550	66,311	73,280	12,819
2023/24	22,481	20,461	22,830	67,325	74,400	13,004
2024/25	22,828	20,834	23,123	68,352	75,530	13,193
Growth Rates						
5 years: 98/99 to 03/04	2.6%	2.0%	0.7%	1.9%	1.6%	2.3% (1.6%)
5 years: 03/04 to 08/09	1.6%	2.0%	1.2%	1.6%	1.6%	1.1% (1.8%)
11 years: 03/04 to 14/15	1.8%	1.9%	0.8%	1.5%	1.5%	1.2% (1.5%)
last 21 years: 03/04 to 24/25	1.7%	1.9%	1.0%	1.5%	1.5%	1.3% (1.4%)

*Values shown in brackets are based on weather normalized actual values.

5.2. Reference Forecast With Power Smart

Table 5.2 provides a summary of historical sales and peaks and the reference forecast with Power Smart, that is, including the effects of BC Hydro's demand-side management program. BC Hydro's total domestic sales with Power Smart include residential, commercial and industrial sales for the BC Hydro service area as well as sales to New Westminster and Fortis BC. BC Hydro's total domestic sales with Power Smart are expected to grow from 49,960 GWh in 2003/04 to 65,967 GWh in 2024/25. BC Hydro's total gross requirements include total domestic sales, firm exports and losses. BC Hydro's total gross requirements with Power Smart are expected to grow from 55,187 GWh in 2003/04 to 72,923 GWh in 2024/25.

It should be noted that new Power Smart activities reflect the current 10-year Power Smart Plan and not any possible Power Smart activities after this period

Again, growth rates of sales vary significantly by sector but within a given sector are fairly consistent over time. For the residential sector, the growth rates of sales with Power Smart are 1.2 per cent for the five years from 2003/04 to 2008/09; 1.5 per cent for the 11 years from 2003/04 to 2014/15; and 1.6 per cent for the 21 years from 2003/04 to 2024/25.

For the commercial sector, the growth rates of sales with Power Smart are 1.4 per cent for the five years from 2003/04 to 2008/09; 1.6 per cent for the 11 years from 2003/04 to 2014/15; and 1.7 per cent for the 21 years from 2003/04 to 2024/25.

For the industrial sector, the growth rates of sales with Power Smart are initially negative at -0.2 per cent for the five years from 2003/04 to 2008/09; 0.0 per cent for the 11 years from 2003/04 to 2014/15; and 0.8 per cent for the 21 years from 2003/04 to 2024/25.

For total gross requirements, the growth rates of sales with Power Smart are 0.7 per cent for the five years from 2003/04 to 2008/09; 1.0 per cent for the 11 years from 2003/04 to 2014/153; and 1.3 per cent for the 21 years from 2003/04 to 2024/25.

BC Hydro's total integrated system peak (system coincident basis excluding Powerex and related losses) with Power Smart is expected to grow from 10,103 MW (9,754MW weather normalized) in 2003/04 to 12,822 MW in 2023/24. The five-year growth rate from 2003/04 to 2008/09 is 0.4 per cent (1.1 per cent weather normalized). The 11-year growth rate from 2003/04 to 2014/15 is 0.8 per cent (1.2 per cent weather normalized). The 21-year growth rate from 2003/04 to 2024/25 is 1.1 per cent (1.3% weather normalized).

The following points are worth noting with respect to the peak forecast:

- The distribution peak forecast was revised reflect changes in the design temperature as well as changes in the 30 year historical period used to determine the average coldest day.
- The transmission peak forecast has been updated to reflect restructuring occurring among B.C.'s resource-based industries. The forecast also includes the closing of Highland Valley Copper beginning in 2007/08 in the South Interior.
- Capacity savings estimates related to Power Smart impacts for each region and the systems were provided by Power Smart.

Table A8.2 in Appendix 8 provides additional details of the 2004 forecast with Power Smart.

Table 5.2. Reference Forecast With Power Smart

	Residen-tial (GWh)	Commer-cial (GWh)	Industrial (GWh)	Total Domestic Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated Sys. Peak* (MW)
Actual (not weather normalized)						
1997/98	13,802	12,466	16,339	43,072	48,342	8,566 (8,672)
1998/99	13,972	12,814	18,077	45,513	50,897	9,026
1999/00	14,572	13,176	17,890	46,376	51,534	8,646
2000/01	14,573	13,654	18,579	47,891	52,978	9,320
2001/02	15,090	13,583	17,739	47,473	52,567	9,003
2002/03	15,287	13,729	18,596	48,685	53,339	8,824
2003/04	15,899	14,151	18,725	49,960	55,184	10,103 (9,754)
Forecast (Residential and System Peak forecasts assume "normal weather")						
2004/05	15,698	14,419	19,096	50,409	55,741	9,979
2005/06	15,999	14,588	18,926	50,640	55,981	9,996
2006/07	16,238	14,789	18,779	50,957	56,339	10,086
2007/08	16,543	14,908	18,569	51,227	56,648	10,155
2008/09	16,842	15,150	18,518	51,786	57,268	10,298
2009/10	17,161	15,457	18,150	52,063	57,591	10,401
2010/11	17,473	15,771	18,380	52,938	58,557	10,558
2011/12	17,778	15,989	18,114	53,215	58,880	10,632
2012/13	18,108	16,265	18,300	54,027	59,774	10,781
2013/14	18,460	16,528	18,532	54,895	60,731	10,923
2014/15	18,812	16,831	18,794	55,835	61,767	11,064
2015/16	19,160	17,138	19,087	56,804	62,836	11,227
2016/17	19,503	17,437	19,382	57,760	63,886	11,391
2017/18	19,850	17,734	19,663	58,703	64,925	11,558
2018/19	20,198	18,023	19,951	59,646	65,963	11,728
2019/20	20,545	18,363	20,265	60,663	67,085	11,901
2020/21	20,886	18,732	20,649	61,773	68,303	12,081
2021/22	21,229	19,117	21,055	62,924	69,568	12,265
2022/23	21,577	19,473	20,335	63,923	70,669	12,448
2023/24	21,925	19,844	21,620	64,942	71,795	12,633
2024/25	22,273	20,217	21,910	65,967	72,923	12,822
Growth Rates						
5 years: 98/99 to 03/04	2.6%	2.0%	0.7%	1.9%	1.6%	2.3% (1.6%)
5 years: 03/04 to 08/09	1.2%	1.4%	-0.2%	0.7%	0.7%	0.4% (1.1%)
11 years: 03/04 to 13/14	1.5%	1.6%	0.0%	1.0%	1.0%	0.8% (1.2%)
21 years: 03/04 to 24/25	1.6%	1.7%	0.8%	1.3%	1.3%	1.1% (1.3%)

* Values shown in brackets are based on weather normalized actuals

Comparing the growth rates in Tables 5.1 and 5.2 for energy and for peak both before and with Power Smart, note that:

- First, energy before Power Smart tracks the key economic drivers real GDP and employment fairly closely. This largely reflects the importance of real GDP and employment as forecast drivers and their strong historical relationships to energy consumption.
- Second, applying the full Power Smart targets reduces energy growth substantially for the first 11 years, but has less impact over latter part of the forecast period. This reflects the absence of new planned/approved Power Smart activity after the current 10-year Power Smart plan.
- Third, peak is growing more quickly than energy on a weather normalized basis. This is due to two main factors: increase in the relative share of residential energy compared to industrial energy; and increase in the relative share of commercial energy compared to industrial energy

Figure 5.2 and 5.3 represent the reference forecast before and with Power Smart for total gross requirements and peak.

Figure 5.2. Reference Forecast Before and With Power Smart – Total Gross Requirements (GWh)

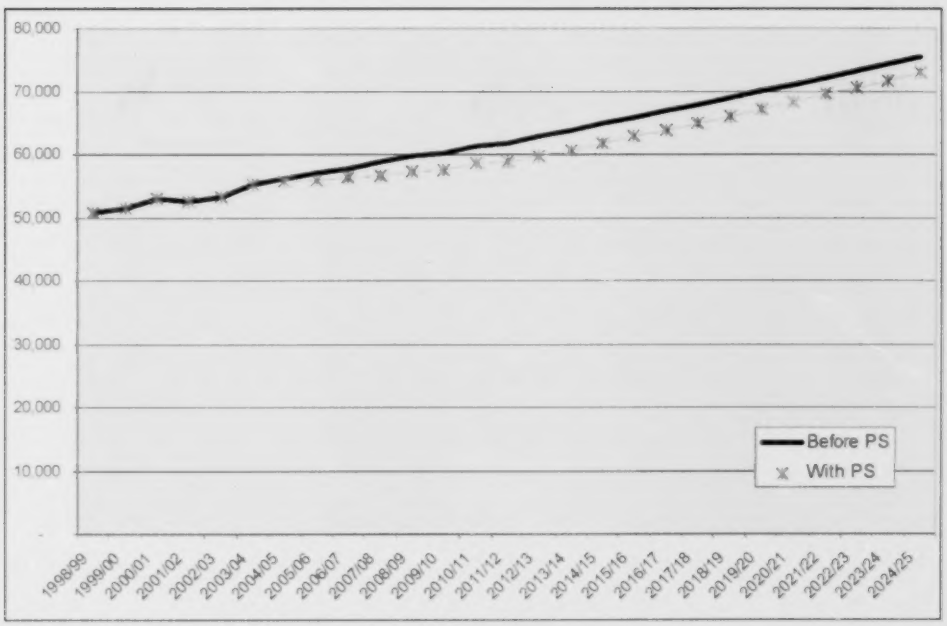
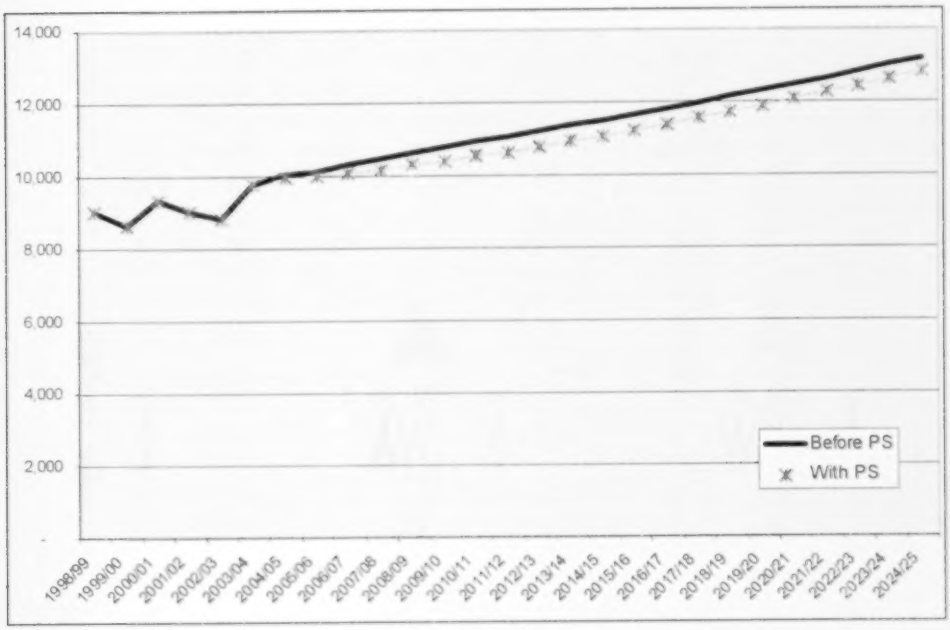


Figure 5.3. Reference Forecast Before and With Power Smart – Integrated System Peak (GWh)



6 Comparison Between 2003/04 and 2004/05 Forecasts

This section compares 2004 energy forecast with the 2003 forecast and discusses the differences between them.

6.1. Total Gross Requirements

Table 6.1 compares total gross requirements for the October 2004 reference forecast including the effects of Power Smart with the October 2003 forecast including Power Smart. For all years, the October 2004 forecast is higher than the October 2003 forecast. The percentage increase in the gross requirements between the October 2003 and the October 2004 forecasts is shown as a percentage in parentheses.

For 2004/05, the 2004 forecast is above the 2003 forecast by 1013 GWh. Much of the increase in 2004/05 is a result of considerably higher than expected sales to the industrial sector in 2004/05, which increased the anchor point for the forecast (see Section 6.4). For 2013/14, the 2004 forecast is 562 GWh above the 2003 forecast, while for 2023/24 the 2004 forecast is 2,120 GWh above the 2003 forecast.

Table 6.1. Comparison of Reference Energy Forecasts With Power Smart: Gross System Requirements

	October 2003 Forecast (GWh)	October 2004 Forecast (GWh)	October 2004 minus October 2003 (GWh)
1998/99	50,897*	50,897*	-
1999/00	51,534*	51,354*	-
2000/01	52,978*	52,978*	-
2001/02	52,567*	52,567*	-
2002/03	53,298*	53,298*	-
2003/04	54,563	55,184*	621 (1.1%)
2004/05	54,728	55,741	1,013 (1.9%)
2005/06	55,086	55,981	895 (1.6%)
2006/07	55,454	56,339	885 (1.6%)
2007/08	56,075	56,648	573 (1.0%)
2008/09	56,641	57,268	627 (1.1%)
2009/10	57,210	57,591	381 (0.7%)
2010/11	57,810	58,557	747 (1.3%)
2011/12	58,410	58,880	470 (0.8%)
2012/13	59,298	59,774	476 (0.8%)
2013/14	60,169	60,731	562 (0.9%)
2014/15	61,088	61,767	679 (1.1%)
2015/16	62,018	62,836	818 (1.3%)
2016/17	62,910	63,886	976 (1.6%)
2017/18	63,832	64,925	1,093 (1.7%)
2018/19	64,758	65,963	1,205 (1.9%)
2019/20	65,709	67,085	1,376 (2.1%)
2020/21	66,699	68,303	1,604 (2.4%)
2021/22	67,657	69,568	1,911 (2.8%)
2022/23	68,656	70,669	2,013 (2.9%)
2023/24	69,675	71,795	2,120 (3.0%)

NB. * = actuals

6.2. Residential Sales

Table 6.2 compares the October 2004 residential reference forecast including Power Smart with the October 2003 forecast including Power Smart. For residential sales, the 2004 forecast is below the 2003 forecast by 118 GWh for 2004/05, above the 2003 forecast by 437 GWh in 2013/14 and above the 2003 forecast by 829 GWh in 2023/24. The main reasons for the increase in forecast residential sales for most of the forecast period are the uplift in the anchor point for 2003/04 and the increase in the forecast number of residential accounts.

Table 6.2. Comparison of Reference Energy Forecasts With Power Smart: Residential Sales

	October 2003 Forecast (GWh)	October 2004 Forecast (GWh)	October 2004 minus October 2003 (GWh)
1998/99	13,972*	13,972*	-
1999/00	14,572*	14,572*	-
2000/01	14,573*	14,573*	-
2001/02	15,090*	15,090*	-
2002/03	15,287*	15,287*	-
2003/04	15,638	15,899*	261 (1.7%)
2004/05	15,816	15,698	-118 (-0.7%)
2005/06	16,042	15,999	-43 (-0.3%)
2006/07	16,280	16,238	-42 (-0.3%)
2007/08	16,526	16,543	17 (0.1%)
2008/09	16,730	16,842	112 (0.7%)
2009/10	16,950	17,161	211 (1.2%)
2010/11	17,171	17,473	302 (1.8%)
2011/12	17,410	17,778	368 (2.6%)
2012/13	17,716	18,108	392 (2.2%)
2013/14	18,023	18,460	437 (2.4%)
2014/15	18,334	18,812	478 (2.6%)
2015/16	18,646	19,160	514 (2.8%)
2016/17	18,957	19,503	546 (2.9%)
2017/18	19,267	19,850	583 (3.0%)
2018/19	19,576	20,198	622 (3.2%)
2019/20	19,882	20,545	663 (3.3%)
2020/21	20,188	20,886	698 (3.5%)
2021/22	20,492	21,229	737 (3.6%)
2022/23	20,794	21,577	783 (3.8%)
2023/24	21,096	21,925	829 (4.1%)

NB. * = actuals

6.3. Commercial Sales

Table 6.3 compares the October 2004 commercial reference forecast including Power Smart with the 2003 forecast including Power Smart. For commercial sales, the 2004 forecast is above the 2003 forecast by 549 GWh for 2004/05, above the 2003 forecast by 427 GWh in 2013/14 and above the 2003 forecast by 547 GWh in 2023/24. The main reasons for the increase in forecast commercial sales are the uplift in the anchor point for 2003/04 and the increase in forecast GDP which affects floor stock.

Table 6.3. Comparison of Reference Energy Forecasts With Power Smart: Commercial Sales

	October 2003 Forecast (GWh)	October 2004 Forecast (GWh)	October 2004 minus October 2004 (GWh)
1998/99	12,814*	12,814*	-
1999/00	13,176*	13,176*	-
2000/01	13,654*	13,654*	-
2001/02	13,583*	13,583*	-
2002/03	13,729*	13,729*	-
2003/04	13,843	14,151*	308 (2.2%)
2004/05	13,870	14,419	549 (4.0%)
2005/06	14,011	14,588	577 (4.1%)
2006/07	14,208	14,789	581 (4.1%)
2007/08	14,467	14,908	441 (3.0%)
2008/09	14,718	15,150	432 (2.9%)
2009/10	14,993	15,457	464 (3.1%)
2010/11	15,280	15,771	491 (3.2%)
2011/12	15,537	15,989	452 (2.9%)
2012/13	15,834	16,265	431 (2.7%)
2013/14	16,101	16,528	427 (2.7%)
2014/15	16,400	16,831	431 (2.6%)
2015/16	16,706	17,138	432 (2.6%)
2016/17	16,979	17,437	458 (2.7%)
2017/18	17,273	17,734	461 (2.7%)
2018/19	17,577	18,023	446 (2.6%)
2019/20	17,900	18,363	463 (2.6%)
2020/21	18,253	18,732	479 (2.6%)
2021/22	18,576	19,117	541 (2.9%)
2022/23	18,930	19,473	543 (2.9%)
2023/24	19,297	19,844	547 (2.9%)

NB. * = actuals

6.4 Industrial Sales

Table 6.4 compares the October 2004 industrial reference forecast including Power Smart with the October 2003 forecast including Power Smart. For industrial sales, the 2004 forecast is above the 2003 forecast by 869 GWh for 2004/05, above the 2003 forecast by 106 GWh in 2013/14 and 1138 GWh above the 2003 forecast in 2023/24. The main reasons for the increase in industrial sales are the uplift in the anchor point for 2003/04 and the increase in forecast GDP.

Table 6.4. Comparison of Reference Energy Forecasts With Power Smart: Industrial Sales

	October 2003 Forecast (GWh)	October 2004 Forecast (GWh)	October 2004 minus October 2003 (GWh)
1998/99	18,077*	18,077*	-
1999/00	17,890*	17,890*	-
2000/01	18,579*	18,579*	-
2001/02	17,739*	17,739*	-
2002/03	18,596*	18,596*	-
2003/04	18,268	18,725*	457 (2.5%)
2004/05	18,227	19,096	869 (4.8%)
2005/06	18,154	18,926	772 (4.3%)
2006/07	18,044	18,779	735 (4.1%)
2007/08	18,069	18,569	500 (2.8%)
2008/09	18,057	18,518	461 (2.6%)
2009/10	18,047	18,150	103 (0.6%)
2010/11	18,052	18,380	328 (1.8%)
2011/12	18,068	18,114	46 (0.2%)
2012/13	18,242	18,300	58 (0.3%)
2013/14	18,426	18,532	106 (0.6%)
2014/15	18,616	18,794	178 (1.0%)
2015/16	18,809	19,087	278 (1.5%)
2016/17	19,008	19,382	374 (2.0%)
2017/18	19,213	19,663	450 (2.3%)
2018/19	19,412	19,951	539 (2.8%)
2019/20	19,615	20,265	650 (3.3%)
2020/21	19,826	20,649	823 (4.2%)
2021/22	20,039	21,055	1,016 (5.0%)
2022/23	20,256	21,355	1,099 (5.4%)
2023/24	20,482	21,620	1,138 (5.6%)

NB * = actuals

6.5. Peak Sales

Compared to 2003, the peak forecast is increased in the short term to reflect the adjustment of the anchor point, current economic conditions and revised forecast drivers. On an integrated system total basis, the 2004 forecast including Power Smart (9,620 MW) is 134 MW higher for 2004/05; 107 MW higher for 2013/14; and 65 MW higher for 2023/24.

The following points are worth noting with respect to the peak forecast:

- An adjustment to the anchor point to reflect more recent 30 year history moderated the definition of average cold day that is the basis for the peak which was offset by the incorporation of actual weather sensitivity

experience from the January 2004 peak resulting in a net upward revision

- The distribution peak forecast was revised upward for 2003/04 to reflect changes in the 2003 population and employment forecasts compared to 2003. A gradual recovery is projected to occur over the next five years, resulting in higher growth over the longer term, using 2003/04 as a base year.
- The transmission peak forecast has been updated to reflect restructuring occurring among BC's resource-based industries. The forecast also includes the closing of a large copper mine in 2007/08 in the South Interior.

Table 6.5. Comparison of Reference Peak Forecasts With Power Smart

	October 2003 Forecast (MW)	October 2004 Forecast (MW)	October 2004 minus October 2003 (MW)
1998/99	9,077*	9,077*	-
1999/00	8,646*	8,646*	-
2000/01	9,320*	9,320*	-
2001/02	9,003*	9,003*	-
2002/03	8,824*	8,824*	-
2003/04	9,620	10,103* (9,754**)	483 (5.0%) 134 (1.4%)
2004/05	9,687	9,979	292 (3.0%)
2005/06	9,787	9,996	209 (2.1%)
2006/07	9,881	10,086	205 (2.1%)
2007/08	10,017	10,155	138 (1.4%)
2008/09	10,144	10,298	154 (1.5%)
2009/10	10,274	10,401	127 (1.2%)
2010/11	10,385	10,558	173 (1.7%)
2011/12	10,502	10,632	130 (1.2%)
2012/13	10,660	10,781	121 (1.1%)
2013/14	10,816	10,923	107 (1.0%)
2014/15	10,991	11,064	73 (0.7%)
2015/16	11,166	11,227	61 (0.6%)
2016/17	11,342	11,391	49 (0.4%)
2017/18	11,517	11,558	41 (0.4%)
2018/19	11,692	11,728	36 (0.3%)
2019/20	11,867	11,901	34 (0.3%)
2020/21	12,043	12,081	38 (0.3%)
2021/22	12,218	12,265	47 (0.4%)
2022/23	12,393	12,448	55 (0.4%)
2023/24	12,568	12,633	65 (0.5%)

* = actuals and ** = weather normalized actual for 2002/03

7 Sensitivity Analysis

BC Hydro's load forecast is sensitive to number of variables including weather, economic conditions, price, etc. BC Hydro's analysis has looked specifically at the sensitivity of the load to changes in the economy (GDP) and the price of electricity. In addition, a Monte Carlo analysis has been completed to look at the sensitivity of the load to a combination five causal factors that impact the forecast.

For peak load, a sensitivity for weather has also been developed that establishes the peak on the basis of a 1 day in 10 year coldest day, versus the current average coldest day.

7.1. Monte Carlo Analysis

A Monte Carlo analysis was completed for the forecast to reflect a range of uncertainties implicit in the load forecast that includes factors beyond GDP and price. Monte Carlo analysis is a technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes

Five major non weather causal factors were used to analyze the sensitivity of the forecast. These include: economic growth rate (reflected by GDP); the electricity rate; the effective energy reduction achieved by demand-side management (DSM) programs; the response to electricity price changes (price elasticity); and electricity intensity.

Probability distributions were assigned to each of these factors. Three values (low, probable and high) were established to reflect possible future levels of each of the factors, with a probability assigned to each.

An uncertainty model employing Monte Carlo simulation methods was used to quantify and combine the probability distributions, reflecting the relationships between the five causal factors and electricity consumption. A probability distribution was thus obtained which showed the likelihood of various load levels resulting from the combined effect of the five factors. This distribution is banded by:

- The low scenario: There is a 10 per cent chance the outcome will be below this value.
- The high scenario: There is a 10 per cent chance that the outcome will exceed this value.

Table 7.1 summarizes the results of calibrating the results of the Monte Carlo uncertainty analysis on the energy and peak forecast before Power Smart.

Table 7.1 Monte Carlo Analysis – Energy and Peak Before Power Smart

	Low Scenario		Reference Forecast		High Scenario	
	Total Gross Requirements (GWh)	Integrated System Peak (MW)	Total Gross Requirements (GWh)	Integrated System Peak (MW)	Total Gross Requirements (GWh)	Integrated System Peak (MW)
2003/04	55,187	10,103	55,187	10,103	55,187	10,103
2008/09	58,457	10,416	59,754	10,645	61,054	10,875
2014/15	62,106	11,013	64,858	11,499	67,667	11,997
2024/25	69,992	12,225	75,530	13,193	81,462	14,232
Growth Rates						
5 years 03/04 to 08/09	1.2%	0.6%	1.6%	1.1%	2.0%	1.5%
11 years 03/04 to 14/15	1.1%	0.8%	1.5%	1.2%	1.9%	1.6%
21 years 03/04 to 24/25	1.1%	0.9%	1.5%	1.3%	1.9%	1.6%

7.2. Uncertainty Assumptions

For each of the five major causal factors, a probability distribution defined by low, probable and high scenarios was assigned.

(a) Long-Term Economic Growth (GDP)

The long-term growth scenarios used were based on average annual GDP increases with a standard deviation of 0.5 per cent.

(b) Electricity Rates

The probable scenario assumes that electricity prices will increase at the rate of inflation (i.e. no increase in real terms). The low and high scenarios assume that annual electricity rate changes will be within a 2.5 per cent band of the probable rate changes.

(c) Effective Energy Reduction of Demand-Side Management (DSM) Programs

The annual low, probable and high reductions from DSM used were 50 per cent, 100 per cent and 150 per cent, respectively, of the expected reductions.

(d) Response to Electricity Price Changes (Elasticity)

The elasticity of electricity demand measures the change in the consumption of electricity in response to changes in variables influencing such demand. However, estimates of elasticity are subject to considerable uncertainty.

(e) Electricity Intensity

Changes in overall electricity intensity are assumed to be within a 0.2 per cent band of the annual change in electricity intensity for that year.

7.3 Temperature Sensitivity of Peak Demand

The forecasts and uncertainty bands described in Table 7.1 assume normal weather. They do not include the effect of colder or warmer than normal (30-year average) temperatures.

8. Residential Forecast

8.1. Summary

Characteristics - Of the three customer classes, residential, commercial, and industrial, the residential sector is the most stable. Growth in the number of residential accounts is about the same as growth in population, which is currently about 1.2%. After many years of growth in use per account, growth in use per account is forecast to be moderate growing at less than 1% over the entire forecast period. Of the 1.46 million residential accounts served at the end of fiscal year 2003/04, 60% were single/duplex, 7% were row houses, 25% were apartments, and 8% were mobile and miscellaneous. Geographically, 58% of the residential accounts are in the Lower Mainland, 10% are in the North Region, 11% are in the South Interior, and 21% are on Vancouver Island. Vancouver Island has the highest percentage of electrically heated accounts because of the limited availability of natural gas. On a sales basis, 53% of residential sales were made in the Lower Mainland, 10% in the north interior, 11% in the south interior, and 26% in Vancouver Island.

Drivers – The drivers of the residential forecast are number of accounts and average annual use per account. Number of accounts is driven by housing starts which is in turn driven by population growth and the trend in people per account. Since household size is gradually decreasing, account growth is expected to be a little higher than population growth. Account growth can vary considerably from year to year in response to BC's economy. In the mid 1990's, about 38,000 accounts were added annually, but by the early 2000's, that number fell to about 13,000. As the economy pulls out of the slump of the early 2000's, account growth is forecast to be about 25,000 - almost double the number of new accounts of a few years ago, but only about two thirds of the number of new accounts added 10 years ago. With growth expected in both the number of accounts and use per account, growth in sales is forecast to be about 1.7% over the entire forecast period.

Trends – At the end of 2007/08, the new forecast for number of accounts is 1,569,205, which is 6,399 or 0.4% above the previous forecast. At the end of 2014/15, the new forecast for number of accounts is 1,771,935, which is 55,065 or 3.2% above the previous forecast. At the end of 2023/24, the new forecast for number of accounts is 2,006,391, which is 89,755 or 4.7% above the previous forecast. The application for the recent rate increase is expected to lower use rate by about 1% in the short term, but over the long term, use rate is not expected to change significantly because of reasons explained in the Forecast Methodology section below.

Electricity Use– BC Hydro's residential sector currently consumes about 33% of BC Hydro's total annual billed sales. This electricity is used to provide a range of services (often called end-uses). The largest end-uses are space heating, water heating, refrigeration, and miscellaneous plug-in load which includes computer equipment and home entertainment systems. Because space and water heating loads are dependent on the outside temperature,

monthly residential sales can be strongly affected by the weather, but sales variations due to the weather tend to cancel out over the long term.

8.2. Forecast Methodology

The forecast for residential sales is calculated as forecast number of accounts times forecast use per account. For the first year of the forecast, growth in number of accounts forecast is based on recent trends. For all subsequent years, percentage growth in number of accounts is set equal to percentage growth in forecast housing starts which are provided by a 3rd party.

The previous forecast for number of accounts relied partly on a population forecast from BC Statistics combined with a forecast trend for household size. However, this approach understated the trend in account growth that BC Hydro was experiencing, so BC Hydro updated methodology to reflect account growth estimates directly by the method described above.

The use rate forecast is based on projections of factors such as housing mix (single family, row house, apartment, etc.), heating fuel choices (electric versus non-electric), appliance penetration rates, appliance life span and changes in electricity demands.

Currently, an estimated 20 per cent of BC Hydro's residential accounts are heated electrically, and on average they require about 14,700 kWh per year. Unless regulations or new laws are introduced, this share will likely increase, although the average usage may not change much for reasons stated below.

Ten years ago the average residential weather-normalized use rate was 10,350 kWh per year, and was increasing by about 125 kWh per year. However, growth in use rate has declined since then, with use rate currently at 10,800 kWh per year, and growing by only an average of 25 kWh per year for the last five years. Improvements in building insulation and appliance efficiency are the main reasons for the moderation of growth in the annual residential use rate. Over the longer term, use rate is not expected to change significantly because of the offsetting effects of the following residential trends.

First, increased electric space heating market share is expected to be offset by smaller housing units. Due to limited availability of land for residential development, the trend in major metropolitan centres is expected to be towards denser housing. Since row houses and apartments are more likely to be built with electric heat than single family homes, the market share for electrically heated housing is expected to increase. Although new row houses and apartments tend to be larger than existing similar dwellings, they are generally smaller in size than single family homes, and therefore have lower space heating load requirements. The increase in market share of electric space heating is also offset to some extent by improvements in building standards, and by the construction of the Vancouver Island gas pipeline, which has made

gas space heat available to Island residents. However, natural gas prices are projected to be higher for Vancouver Island compared to the Mainland over the entire forecast period. As a result, the growth in the penetration rate of gas heating is anticipated to be slower for Vancouver Island than it was for the Mainland.

Second, more efficient appliances versus higher penetration. Manufacturers throughout Canada and the United States are expected to continue to improve the energy efficiency of major electrical appliances. As older models wear out and are replaced by newer ones, electricity consumption for major appliances such as refrigerators, freezers, ovens and ranges is forecast to decrease. However, new models of these major appliances tend to be larger than models currently in use. Some of the reduction in electricity use resulting from improvements in electricity efficiency will be offset by an increase in appliance size.

Third, a projected decrease in the number of people per household would tend to reduce electricity use per account. However, this reduction is expected to be offset by an increase in the penetration level of small appliances. An increase in electricity use is also projected from lifestyle changes and technological improvements. The latter are expected to cause an increase in demand for electronic, entertainment and telecommunication devices in the home. A trend towards home offices is also expected to produce a long-term increase in residential electricity consumption. In the long term, the expected overall impact of these various trends is that the factors working to increase the use rate will be offset by the factors working to decrease it, leading to the use rate levelling.

8.3 Forecast Overview

To develop the residential sales forecast for the entire BC Hydro service area, the total service area was divided into four customer service regions, and a forecast was prepared for each region. These regions are Lower Mainland, Northern Region, South Interior and Vancouver Island. For each region, a 3rd party housing stock forecast was prepared based on the number of residential accounts forecast in the region, and on other regional factors such as trends in housing mix and gas availability.

A use rate forecast was also developed for each region based on projections of penetration rates and individual consumption levels by end use (space heating, water heating, major appliances and small lifestyle appliances).

The residential sales forecast for a region is the sum of the requirements for each end use. The requirements for each end use are the product of the number of accounts having that end use and the energy used by an average account having that end use.

Table 8.1 forecasts residential sales before Power Smart, including sales by region. Figure 8.1 summarizes residential consumption by end use for the years 2003/04 and 2024/25.

Billed residential sales were 15,899 GWh in 2003/04 but on a weather normalised basis were slightly higher at 15,902 GWh. Residential sales, before incremental Power Smart impacts, are forecast to grow from 15,899 GWh in 2003/04 to 17,234 GWh in 2008/09, to 19,033 GWh in 2013/14, and to 22,828 GWh in 2024/25. These increases represent growth rates of 1.6 per cent over the next five years (2003/04 to 2008/09), 1.8 per cent over the next 11 years (2003/04 to 2013/14), and 1.7 per cent over the next 21 years of the forecast (2003/04 to 2024/25).

The two main drivers of the residential forecast are the forecast of the number of residential accounts, and the forecast of use rate (annual electricity consumption per residential account). These are discussed in detail below.

For the first four years of the forecast period (2004/05 to 2007/08), the growth rate is less than for the longer term, reflecting BC Hydro's applied for rate increase. Starting in 2008/09, the 2004 forecast gradually becomes higher than the 2003 forecast because of a higher forecast for number of accounts.

Forecast growth rates for future residential energy sales are below the most recent five-year average. The reasons for slowing growth rates for energy sales include the impact of the rate increase, a slowing of forecast penetration of energy using appliances as well as the anticipated slowing of the penetration of electric space heating.

Table 8.1. Residential Sales Before Power Smart

	BC Hydro Total	Lower Mainland	Vancouver Island	South Interior	Northern Region
	Sales (GWh)	Sales (GWh)	Sales (GWh)	Sales (GWh)	Sales (GWh)
Actual					
1998/99	13,972	7,355	3,718	1,541	1,357
1999/00	14,572	7,670	3,909	1,583	1,409
2000/01	14,573	7,695	3,863	1,617	1,397
2001/02	15,090	7,975	4,001	1,656	1,458
2002/03	15,287	8,120	3,981	1,729	1,457
2003/04	15,899	8,447	4,123	1,803	1,526
Forecast (Residential sales forecast based on "normal weather")					
2004/05	15,844	8,413	4,096	1,750	1,502
2005/06	16,220	8,672	4,219	1,792	1,536
2006/07	16,515	8,844	4,299	1,817	1,556
2007/08	16,880	9,054	4,397	1,848	1,580
2008/09	17,234	9,254	4,500	1,878	1,602
2009/10	17,601	9,462	4,603	1,911	1,625
2010/11	17,964	9,671	4,703	1,943	1,648
2011/12	18,326	9,877	4,805	1,974	1,671
2012/13	18,684	10,083	4,903	2,005	1,693
2013/14	19,033	10,285	4,998	2,035	1,715
2014/15	19,376	10,485	5,090	2,066	1,736
2015/16	19,715	10,682	5,181	2,095	1,757
2016/17	20,059	10,882	5,273	2,126	1,778
2017/18	20,405	11,085	5,365	2,156	1,799
2018/19	20,754	11,290	5,457	2,187	1,820
2019/20	21,100	11,494	5,547	2,218	1,842
2020/21	21,442	11,695	5,636	2,248	1,863
2021/22	21,785	11,897	5,726	2,279	1,883
2022/23	22,133	12,103	5,815	2,310	1,904
2023/24	22,481	12,310	5,905	2,341	1,925
2024/25	22,828	12,516	5,994	2,372	1,946
Growth Rates					
5 years: 98/99 to 03/04	2.6%	2.8%	2.1%	3.2%	2.4%
5 years: 03/04 to 08/09	1.6%	1.8%	1.8%	0.8%	1.0%
11 years: 03/04 to 14/15	1.8%	2.0%	1.9%	1.2%	1.2%
21 years: 14/15 to 24/25	1.7%	1.9%	1.8%	1.3%	1.2%

The reasons for the difference between the two forecasts are: (a) higher anchor point; (b) higher number of accounts forecast for 2008/09 forward; and (c) different forecast use rate.

(a) Anchor Point: In 2003, the forecast called for 2003/04 weather normalized billed sales with Power Smart impacts to be 15,638 GWh. Actual weather

normalized billed sales for 2003/04 were 15,902 GWh, 264 GWh or 1.69% higher than forecast.

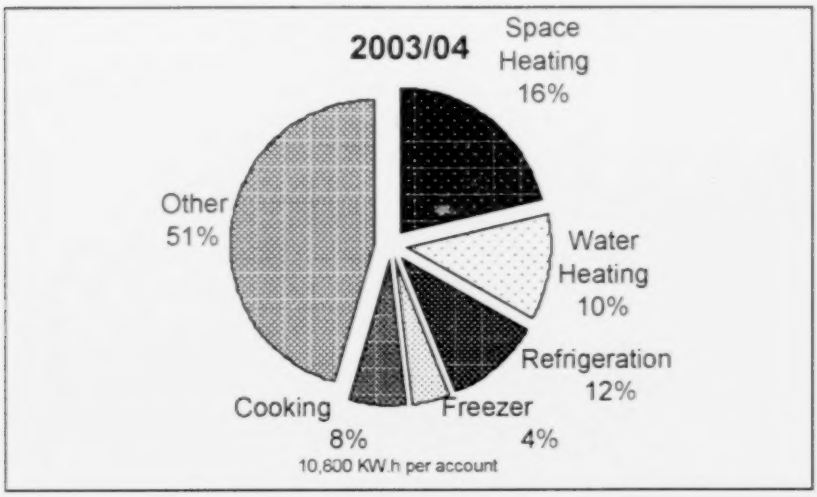
(b) Number of Accounts: Since forecast sales are calculated by multiplying forecast use rate by forecast accounts, the number of accounts forecast can have a significant impact on the sales forecast. However, for the first four years of the forecast, the number of accounts forecast in 2004 is very similar to the previous forecast. The ending number of accounts for 2003/04 was 1,461,897 which was 3,160 accounts or 0.2% above the forecast value of 1,465,057.

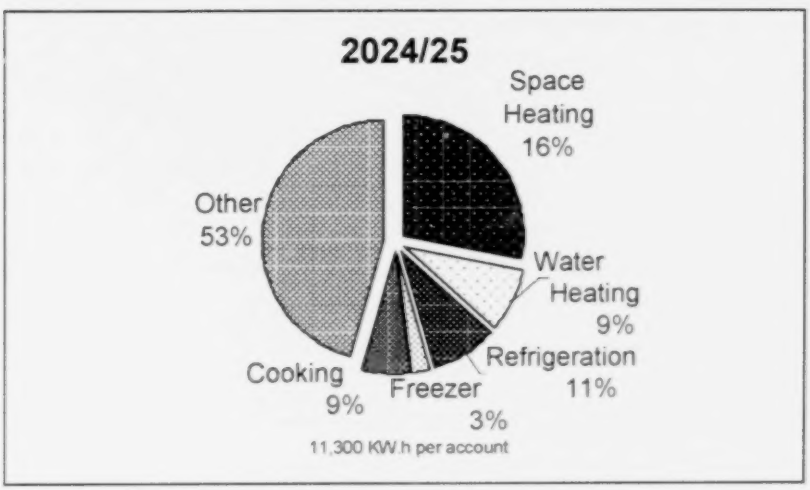
(c) Use Rate: The main reason that 2003/04 sales were above forecast is because the annual use per account was higher than expected. Use rate in 2003/04 was 182 KWh or 1.69% higher than forecast. Weather had a very small impact on billed sales for 2003/04 - actual billed sales were 15,899 GW.h compared to weather normalized billed sales of 15,902 GW.h - a difference of 3 GW.h or 0.02%. Therefore the variance in use rate accounted for virtually all of the variance in residential billed sales for 2003/04.

The 2003 forecast called for use rate to show a steady increase over the entire forecast period. In comparison, the 2004 forecast starts with a higher use rate for 2004/05 than the 2003 forecast, but then has use rate declining by about 0.5% in 2005/06, and then increasing from that point forward. By 2008/09, use rate is forecast to be back to the level forecast for 2004/05. The 2004 forecast also calls for a smaller growth in use rate. In 2003, use rate was forecast to show growth of 0.2% over the next 5 years, 0.3% over the next 10 years, and also 0.3% over the next 20 years. The 2004 forecast calls for use rate growth of -0.2% over the next 5 years, 0.05% over the next 10 years, and 0.15% over the next 20 years.

The main reason for the decline in use rate in the near term, and the slower growth in use rate over the long term, is assumption of the load impact associated with the 8.9% increase in electricity rates applied in 2004.

Figure 8.1. Residential Consumption Before Power Smart by End Use for Selected Years





9 Commercial Forecast

9.1. Summary

Characteristics - BC Hydro's commercial sector provides electricity to British Columbia's service sector. It is a very diverse set of BC Hydro customers who operate a wide range of facilities such as office buildings, retail stores, institutions (i.e., hospitals and schools) and transportation infrastructure. The largest portions of these facilities are buildings (approx. 85%), with the remaining "non-buildings" including facilities and infrastructure such as transportation systems and public utilities.

Electricity Use– BC Hydro's commercial sector currently consumes about 28% of BC Hydro's total annual billed sales. This electricity is used to provide a range of services (often called end-uses) such as lighting, ventilation, heating, cooling, refrigeration, hot water, etc. These needs vary considerably between the different types of buildings. Unlike the residential sector, the diversity of use in the commercial sector means that consumption in the sector is not strongly correlated to weather.

Drivers – At an aggregate level, consumption in the commercial sector is tied closely with economic activity in the province - the stronger the economy the more services need, the greater the electricity consumption of the commercial sector. As a result future economic trends (i.e., provincial GDP - Gross Domestic Product and Employment).are good indicators of future electricity consumption in the sector. At a more detailed level, the consumption in the commercial sector is driven by the number of buildings and facilities and the amount of energy required to meet all energy needs.

Trends – Electricity consumption of the commercial sector can vary considerably from year to year reflecting the level of activity in BC's service sector. During periods where the economy is strong, electricity sales tend to be high. Sales to BC Hydro's commercial sector in 2003/04 grew by 3.1 per cent reflecting the performance of the BC economy (GDP) which grew at 2.2 per cent in 2003. This is higher that the 1.3% growth in commercial sales that was forecast last year under the expectation that the GDP would grow at 1.5 per cent. The BC Economy is anticipated to continue on a positive upswing and grow at 2.8% in 2004 and 3.1% in 2005 contributing to sustained growth in the commercial sector.

Forecast - Billed commercial sales were 14,151 GWh in 2003/04. Commercial sales, before incremental Power Smart impacts, are forecast to grow from 14,151 GWh in 2003/04 to 15,642 GWh in 2008/09, to 17,471 GWh in 2014/15, and to 20,834 GWh in 2024/25. These increases represent growth rates of 2.0 per cent over the next five years (2003/04 to 2008/09), 1.9 per cent over the next 11 years (2003/04 to 2014/15), and 1.9 per cent over the next 21 years of the forecast (2003/04 to 2024/25).

9.2. Approach

The commercial sales forecast is based primarily on a bottom-up or end-use forecast. This methodology focuses on the "stock" of buildings or facilities and how they consume energy in the sector. There are also top-down components to the forecast driven by general economic variables (such as GDP and employment) that account for year-to-year fluctuations in electricity sales as a result of changes in occupancy of the building stock.

The building portion of the commercial sector accounts for 83% of the commercial sector sales. Non-buildings, which account for the remainder include facilities such as transportation and communication infrastructure, pipeline transport, grain elevators and utilities.

As an end-use or bottom-up forecast, BC Hydro's commercial sector forecast focuses on the demand for energy consuming end uses (i.e. heat, light and refrigeration) to meet the requirements for commercial buildings. In its simplest form, the forecast is the product of the commercial sector building floor stock (i.e. the floor area in square feet) and the intensity of end-use demand per unit of floor stock. BC Hydro's forecast disaggregates commercial buildings in the province into 13 building types, listed in Table 9.1, and up to 10 different end uses (including space heating, lighting, hot water, ventilation, and so on).

Table 9.1. BC Hydro Commercial Sector Building Types

Small Office	Large Office
Non-Food Retail	Grocery
Restaurants	Warehouse
Schools	Colleges/Universities
Hotel/Motel	Hospitals
Nursing Homes	Apartments
Other Buildings	

Notes: Apartments include apartment common areas only. Other Buildings includes amusement and recreation facilities, religious organizations and protective services.

The growth of commercial floor stock depends on many different factors including economic trends, population growth, demographics and employment. For example, an aging population will require an increased number of health care facilities and growth in tourism will be reflected in the number of hotels, restaurants and recreation facilities.

The intensity of end-use demand will change with factors such as the turnover of building stock and the evolution of the energy end-use technology. This can have both positive and negative impacts on energy intensity. As an example, some of the trends in new buildings that act to reduce energy intensities include:

- change to T8 linear fluorescent lighting with electronic ballasts;
- improved thermal building characteristics with higher insulation levels;
- double pane with thermal break window glazing; and

- improved cooling equipment efficiencies.

In contrast, other loads will put an upward pressure on building energy consumption, such as:

- greater lighting levels in retail stores;
- increased use of computers and other plug loads;
- new design practices that require higher ventilation rates in some buildings, such as in schools and hospitals; and
- increased saturation of space cooling in selected segments.

Electricity sales in the commercial sector building stock also depend on the level of economy activity as a whole, regardless of the installed floor stock. For example, electricity sales to stores, warehouses or hotels will vary with factors such as retail sales, wholesale/retail trade and tourism. Significant fluctuations in electricity sales growth in the commercial sector can result from changes in the performance of the local economy. In addition, it is assumed the growth in the non-building commercial facilities will vary with trends in the high-level drivers: GDP, employment and population.

As a result, the commercial forecast relies extensively on both short- and long-term population, demographic and economic forecasts. In the short term, variations in the economy on a year-to-year basis will effect electricity sales in terms of occupancy rates and/or performance of the province's commercial buildings and facilities. In the long term, the size and structure of the economy as well as the size and age of the population will dictate what types of commercial buildings and facilities are constructed to meet the needs of the province's service sector. Over the long term, commercial sales growth is likely to be influenced by factors including:

- A growing population, which increases the demand for most general services;
- A gradual shift in the structure of British Columbia from a goods-based to a more service-based economy;
- An aging population, which will require increased heath care services;
- Increases in electric intensity, a result of greater use of electronic and information end-use technologies;
- Continued growth in the tourism sector;
- New electricity-using technologies becoming more common in commercial establishments;
- Continued growth of Vancouver as an international finance centre;
- BC's continued role as Canada's link with Pacific markets; and
- The potential for further development of a high tech sector within the province.

9.3. Major Trends

The BC economy continues to be strongly influenced by primary resource industries and their associated international markets. BC's service sector has however been growing significantly in recent years and currently employs 80 per cent of the total provincial population and is responsible for approximately 76 per cent of the province's GDP. This compares to 20 per cent and 24 per cent for employment and GDP for the goods-producing sector. As a result, the service sector has been the primary employment growth engine for the province and this trend is expected to continue. In addition, the BC service sector is also much less susceptible to fluctuations in international markets than the goods-producing sector, which contributes to its stronger and more stable growth.

The following discussion outlines some of the economic trends in BC four regions that will impact commercial activity in the province and as a result the consumption of electricity within the sectors buildings and facilities.

9.4. Lower Mainland

The Lower Mainland and particularly Greater Vancouver is the key economic region of BC. Its economy is highly diversified with over 80% of employment in the region within the services sector. This isolates the region from many of the "boom and bust" cycles experienced in other parts of the province. This diversity contributed to the Lower Mainland experiencing growth of 3.8% in commercial sales in F2003/04 and a 5-year historic growth of 2.5%.

Sales to the commercial sector in the Lower Mainland vary across the region. Greater Vancouver's commercial sector growth is relatively strong due to its extensive service and high technology sectors. In other parts of the region, a mixture of agriculture, resource development and tourism will have their own impacts on sales. Overall, it is expected that commercial sales growth before Power Smart in the Lower Mainland will be 2.4 per cent, 2.2 per cent and 2.0 per cent over the next five, 11, and for 21 years of the forecast respectively.

The outlook for the region includes impacts associated with the region hosting the 2010 Winter Olympics. There are a modest number of buildings, facilities and infrastructure projects that are being constructed to directly support Olympic events in the region. There is however potential for many indirect impacts which are much more difficult to quantify that may exist beyond the 2010 time frame.

9.5. Vancouver Island

Commercial Sales on Vancouver Island grew by 1.2% in 2003/04, slightly lower than the historic 5-year average annual growth of 1.5%.

Vancouver Island benefits from some economic diversity in the south and growing diversity in the central part of the Island. There is a strong resource component to Island's economy particularly in the central and northern parts of the region.

Sales to Vancouver Island's service sector will be the result of a variety of mixed trends over the next few years. Overall the region's sector is expected to grow at 1.2 per cent, 1.4 per cent and 1.7 per cent over the next five, 11, and 21 years of the forecast, respectively, before Power Smart.

Factors contributing to this growth include the following:

- Possible increases in employment in the public sector following several years of provincial government reductions
- Some improvements in the tourism but with uncertainty resulting from a strengthening Canadian dollar
- Favourable rulings in the softwood lumber disputes
- An increasingly active aquaculture sector
- Continued attractiveness of the region as a retirement destination particularly in the south and central.

9.6. South Interior

Commercial Sales in BC's South Interior grew by 2.9% in 2003/04, much higher than 5-year historical average annual growth of 2.0%.

BC's South has also seen economic diversification though tourism (including golf courses, casinos and ski resorts), through diversification of the agricultural industry (wine and fruit) and as a retirement centre. This bodes well for the economic strength of the region and in turn, stability of commercial sales. Overall the service sector comprises about 75% of the total employment of the region compared to 25% in the goods producing sectors.

The resource sector has rebounded in 2003 through strength in the forestry sector despite the softwood lumber dispute, and positive prices of many base metals and for coal. However other factors such as the closure of Highland Valley Copper (expected to begin in 2007/08) and uncertainties in the resource sector will likely have a moderating effect on this growth.

The forecast for electricity sales to the commercial sector in the South Interior is anticipated to grow at 1.9 per cent, 1.8 per cent and 1.8 per cent over the next five, 11, and 21 years of the forecast, respectively, before Power Smart.

9.7. Northern Region

Commercial Sales in BC's Northern Region grew by 1.8% in 2003/04, much higher than the 5-year historical average annual growth of –0.4%.

The Northern Region is the most resource dependent of BC's four regions creating many single-industry communities who are susceptible to significant swings in economic activity. This includes a dependency on forestry throughout the region, coal mining and oil and gas in the north-east and aquaculture in the north-west.

Commercial electricity sales in the Northern Region are expected to grow, before Power Smart, at 0.9 per cent, 0.8 per cent and 0.9 per cent over the next five, 11, and for the last 21 years of the forecast, respectively. This moderately low growth is a result of the expectation that the region will continue to be heavily dependent of resource-based industries. Softness in the forestry sector particularly associated with the mountain pine beetle infestation has contributed to a more modest economic outlook. This is expected to be partially offset by an improving outlook in the mining industry

Table 9.2 and summarize the total BC Hydro and regional commercial sector forecast before Power Smart. The forecast future growth rates for the commercial sector as a whole and for most regions is lower than the recent five year average growth rate. The main reason for this is the assumed impact of the rate increase on electricity use and electricity sales.

Table 9.2. BC Hydro Regional Commercial Sales Forecast Before Power Smart

	BC Hydro Total	Lower Mainland	Northern Region	South Interior	Vancouver Island
	Sales (GWh)	Sales (GWh)	Sales (GWh)	Sales (GWh)	Sales (GWh)
Actual					
1998/99	12,814	7,991	1,211	1,158	2,106
1999/00	13,176	8,478	1,249	1,208	2,241
2000/01	13,654	8,871	1,233	1,264	2,286
2001/02	13,583	8,828	1,180	1,298	2,277
2002/03	13,729	8,938	1,178	1,323	2,290
2003/04	14,151	9,280	1,194	1,361	2,317
Forecast					
2004/05	14,521	9,557	1,217	1,401	2,345
2005/06	14,731	9,744	1,218	1,413	2,354
2006/07	15,049	9,995	1,229	1,442	2,384
2007/08	15,316	10,193	1,237	1,470	2,416
2008/09	15,642	10,436	1,250	1,497	2,460
2009/10	15,983	10,705	1,258	1,520	2,499
2010/11	16,333	11,008	1,260	1,537	2,528
2011/12	16,581	11,179	1,271	1,562	2,570
2012/13	16,879	11,381	1,286	1,593	2,620
2013/14	17,156	11,578	1,298	1,620	2,660
2014/15	17,471	11,800	1,307	1,651	2,713
2015/16	17,777	12,016	1,316	1,680	2,765
2016/17	18,077	12,230	1,323	1,710	2,816
2017/18	18,382	12,444	1,331	1,739	2,867
2018/19	18,678	12,654	1,338	1,769	2,918
2019/20	19,022	12,891	1,354	1,802	2,975
2020/21	19,373	13,133	1,370	1,836	3,033
2021/22	19,731	13,382	1,387	1,872	3,092
2022/23	20,090	13,629	1,403	1,907	3,152
2023/24	20,461	13,885	1,420	1,943	3,214
2024/25	20,834	14,142	1,437	1,979	3,276
Growth Rates					
5 years: 98/99 to 03/04	2.0%	3.6%	-2.8%	3.9%	1.9%
5 years: 03/04 to 08/09	2.0%	2.4%	0.9%	1.9%	1.2%
11 years : 03/04 to 14/15	1.9%	2.2%	0.8%	1.8%	1.4%
21 years: 03/04 to 24/25	1.9%	2.0%	0.9%	1.8%	1.7%

10 Industrial Forecast

10.1. Summary

Characteristics - BC Hydro's industrial sector is concentrated in a limited number of industries, the most important of which are pulp and paper, wood products, chemicals, metal mining and coal mining. The remaining industrial load is made up of a large number of small and medium sized manufacturing establishments.

Electricity Use - BC Hydro's industrial sector currently consumes some 40% of BC Hydro's total annual billed sales This electricity is used to provide a range of services including fans, pumps, compression, conveyance, processes such as cutting, grinding, stamping and welding and electrolysis. In comparison to the commercial sector, space conditioning, lighting, refrigeration and freezing loads are relatively less important. They can, however, be significant in small and medium sized facilities.

Trends - Electricity consumption in the commercial sector is quite volatile, driven substantially by economic conditions in the United States and Asia that affect commodity markets. Export sales to these three countries are a key determinant of domestic industrial output and of the industrial demand for electricity. Other key determinants of the industrial load include increasing levels of self-generation and of co-generation.

Drivers – As in the case of the commercial sector, industrial electricity consumption is tied closely with the level of economic activity in the province, that is there is a strong relationship between industrial electricity consumption and provincial Gross Domestic Product. Future economic trends are a good indicator of future electricity consumption in the industrial sector. However, this is mediated by the fact that the industrial share of provincial GDP has been declining. This is accounted for through the use of regression model based forecast that incorporate the changing relationship between GDP and industrial sales.

Forecast - Billed industrial sales were 18,725 GWh in 2003/04. Forecast sales to industrial customers before Power Smart, are expected to grow from 18,737 GWh in 2003/04 to 19,784 GWh in 2008/09, to 20,900 GWh in 2013/14, and to 24,676 GWh in 2024/25. These increases represent growth rates of 1.2% over the next five years (2003/04 to 2008/09), 0.8% over the next 11 years (2003/04 to 2014/15), and 1.0% over the next 21 years of the forecast (2003/04 to 2024/25).

10.2. Sector Outlooks

Resource extraction and processing form the basis of BC's industrial economy. Key activities within the industrial include metal mining, coal mining, ore processing and smelting, wood extraction, saw milling, pulp and paper and chemical production. Approximately 80 per cent of BC Hydro's sales to the industrial sector are made to large-scale customers involved in the extraction and processing of natural resources and the remaining are smaller manufacturing companies.

Given the importance of the forestry and sawmilling, pulp and paper and mining sectors for BC Hydro's electricity load, this section summarises the current situation and prospects in each of these sectors. It should be noted that all three of these sectors have experienced particularly large swings in the level of economic activity over the past decade.

10.2.1. Medium-Term Forestry and Pulp and Paper Outlook

Shipments of lumber from British Columbia, which have recently been averaging between 12 billion and 13 billion board feet per year, now go almost entirely to the United States, Japan and other parts of Canada. Shipments to European and other markets, which peaked at about 1.5 billion board feet in the late 1980s, have fallen to about 500 million board feet. This means that the health of the B.C. lumber market depends critically on the strength of the American and Japanese economies as well as the degree of market access for B.C. lumber. The American lumber market has shown strength because of strong housing demand, but might fall back with anticipated rising interest rates.

Key issues for B.C. lumber sales in the medium term include:

- Changes in domestic timber supply. Move to smaller, poorer quality, second growth timber on Vancouver Island and destruction of large volumes of wood by beetles are expected to eventually raise timber costs. In the shorter term there could be a significant increase in the allowable cut to take advantage of dead and beetle-damaged timber.
- Changes in lumber demand. On-going oversupply in the North American market are likely to continue to provide downward pressure on prices over the medium term and lead to more rationalisation of mills and mill closures. Some mills have substantially improved productivity in recent years by improving product flow, replacing older equipment with newer and more efficient equipment, and improving use of labour on the mill floor.
- Impact of market access disputes. On-going disputes concerning access to the United States market create uncertainty, reduce cash flow and limit opportunities for upgrading B.C. mills. Some mills have reacted to tariffs and anti-dumping duties by increasing production and exports rather than reducing both.

10.2.2. Medium-Term Forestry and Pulp and Paper Outlook

BC pulp capacity is about 9.3 million metric tons per year with about 58% bleached softwood kraft pulp, 28% thermal mechanical pulp (TMP) or chemical thermal mechanical pulp (CTMP), 5% unbleached kraft and about 9% in other grades. Consolidation in the pulp and paper industry, coupled with three years of relatively poor markets in both North America and overseas through 2003, have led to strong pressures to rationalise production and reduce costs. A number of BC pulp and paper mills are reasonably high cost producers compared to competitors, particularly in emerging markets, and rising fibre costs combined with a strong Canadian dollar have furthered weakened profitability. For the near term, however, the pulp and paper outlook is positive, driven by string demand in South and South East Asia.

Key issues for BC pulp and paper sales in the medium term include:

- Ongoing decline in the North American newsprint market, which is expected to foreshadow a slow decline in the world newsprint market. However, the use of recycled newsprint may have peaked which should stabilise the demand for new fibre.
- Slowing demand growth for most printing and writing paper grades, with some limited bright spots such as directory paper. Several BC companies appear to be making a successful transition away from kraft pulp and newsprint to higher value products.
- Growing demand for paper products on the part of China (a positive factor for B.C.) combined with expected increased supply in China from new and very large mills (a negative factor for B.C.) as well as continued expansion of production of newer, low cost mills in developing countries.
- Rationalisation of the pulp and paper industry, leading to decisions on investment and upgrading made on a global basis, with negative implications for high cost paper machines and pulp and paper mills, including some B.C. facilities. Several BC pulp and paper companies announced that they had achieved major improvements in efficiency and cost reduction in 2003.

10.2.3. Medium-Term Mining Outlook

The mining sector had gross sales of some $3.5 billion in 2003. Some 20 mines currently purchase power from BC Hydro, with more metal mines and coal mines currently in production. Most production is for export and there is relatively little domestic processing or manufacturing based on mineral production. Coal is sold primarily to Japan and China with the demand for metallurgical coal decreasing in Japan but increasing in China. Precious and base metals are exported to a number of countries. The domestic base metal industry had been losing ground to foreign competitors for some years, although there are some signs of domestic strength.

Key issues for B.C. mining sales in the medium term include:

- An increase in the Canadian dollar has tended to reduce profitability because most costs are in Canadian dollars. At the same time, copper and gold prices have been strong so that the overall impact on cash flow has been positive.
- Exploration in BC has been limited for several reasons including environmental regulations that are stronger than in many countries and unresolved native land claims.
- Few high quality ore deposits have been found in BC in recent years, while major finds have taken place in Latin America, Africa and Indonesia.
- Recently there have been some signs of renewed interest in the mining industry but these have yet to be translated into a significant increase in new mines.

10.3. Methodology

The main determinant of industrial electricity sales is the level of forecast activity in the industrial sector. Since long-term forecasts for industrial GDP are not available, the forecast uses total provincial GDP as a proxy. At present, three sources of information on GDP are used for the load forecast. These sources are: B.C. Ministry of Finance, Second Quarterly Report 2004; Malatest and Associates, June 2004; and a ratio based on U.S. Department of Energy forecast for Canadian GDP, Annual Energy Outlook 2004, December 2003.

For the period 2004 through 2008, the GDP forecast is a weighted average of the B.C. Ministry of Finance and the Malatest and Associates Forecast. For 2009 through 2024, the GDP forecast is a weighted average of the Malatest and Associates and the DOE forecasts.

This forecast uses a weighted average for the following reasons:

- Since the three forecasts are based on somewhat different data sources and methodologies, pooling information through a weighted average forecast reduces risk;
- The B.C. Ministry of Finance forecast is not available for the 20 years needed for the load forecast so the B.C. Ministry of Finance forecast needs to be supplemented by other forecasts; and
- The weighted average forecast appears to track future outcomes better than a single forecast.

10.4. Industrial Models

Table 10.1 compares the industrial forecasts based on the ordinary least squares (OLS) and maximum likelihood (ML) regression analyses for Model 1 before Power Smart. The OLS industrial forecast rises from 18,737 GWh in 2003/04 to 24,897 GWh in 2024/25. The ML forecast is very similar, rising from 18,737 GWh in 2003/04 to 24,789 GWh in 2024/25. These forecasts do not include the impact of electricity price changes. Model 1 excludes the impacts of industrial strikes while Model 2 includes them. For details, see Appendix 7.

Table 10.1. Forecast Industrial Sales Before Power Smart (GWh) Model 1

Year	Trans-mission OLS	Trans-mission ML	Distrib-ution OLS	Distrib-ution ML	Indus-trial OLS	Indus-trial ML
1994/95	13,347	13,347	3,740	3,740	17,087	17,087
1995/96	13,948	13,948	3,682	3,682	17,630	17,630
1996/97	13,613	13,613	3,834	3,834	17,447	17,447
1997/98	12,553	12,553	3,786	3,786	16,339	16,339
1998 99	14,257	14,257	3,820	3,820	18,077	18,077
1999/00	14,062	14,062	3,828	3,828	17,890	17,890
2000/01	15,052	15,052	3,627	3,627	18,679	18,679
2001/02	13,855	13,855	3,884	3,884	17,739	17,739
2002/03	14,550	14,550	4,046	4,046	18,596	18,596
2003/04	14,832	14,832	3,893	3,893	18,737	18,737
2004/05	14,993	14,982	3,930	3,935	18,923	18,917
2005/06	15,240	15,227	3,959	3,966	19,199	19,193
2006/07	15,495	15,480	3,988	3,997	19,483	19,477
2007/08	15,749	15,732	4,018	4,028	19,767	19,760
2008/09	16,002	15,983	4,048	4,059	20,050	20,042
2009/10	16,253	16,232	4,077	4,090	20,330	20,322
2010/11	16,548	16,525	4,112	4,126	20,660	20,651
2011/12	16,777	16,752	4,139	4,154	20,916	20,906
2012/13	17,011	16,984	4,166	4,183	21,177	21,167
2013/14	17,251	17,222	4,194	4,213	21,445	21,436
2014/15	17,506	17,475	4,224	4,244	21,730	21,719
2015/16	17,769	17,735	4,255	4,276	22,024	22,011
2016/17	18,026	17,991	4,285	4,308	22,311	22,299
2017/18	18,290	18,253	4,316	4,340	22,606	22,593
2018/19	18,561	18,521	4,348	4,373	22,909	22,894
2019/20	18,838	18,796	4,380	4,407	23,218	23,203
2020/21	19,109	19,065	4,412	4,441	22,521	23,506
2021/22	19,387	19,341	4,445	4,475	23,832	23,816
2022/23	19,672	19,623	4,478	4,510	24,150	24,133
2023/24	19,963	19,912	4,512	4,546	24,475	24,458
2024/25	20,260	20,207	4,547	4,582	24,807	24,789

Table 10.2 compares the forecasts based on the OLS and ML regression analyses for Model 2 before Power Smart. The OLS industrial forecast rises from 18,737 GWh in 2003/04 to 24,420 GWh in 2024/25. The ML forecast is very similar, rising from 14,832 GWh in 2003/04 to 24,188 GWh in 2024/25.

Table 10.2. Forecast Industrial Sales Before Power Smart (GWh) Model 2

Year	Trans-mission OLS	Trans-mission ML	Distrib-ution OLS	Distrib-ution ML	Indus-trial OLS	Indus-trial ML
1994/95	13,347	13,347	3,740	3,740	17,087	17,087
1995/96	13,948	13,948	3,682	3,682	17,630	17,630
1996/97	13,613	13,613	3,834	3,834	17,447	17,447
1997/98	12,553	12,553	3,786	3,786	16,339	16,339
1998.99	14,257	14,257	3,820	3,820	18,077	18,077
1999/00	14,062	14,062	3,828	3,828	17,890	17,890
2000/01	15,052	15,052	3,627	3,627	18,679	18,679
2001/02	13,855	13,855	3,854	3,884	17,739	17,739
2002/03	14,550	14,550	4,046	4,046	18,596	18,596
2003/04	14,832	14,832	3,893	3,893	18,737	18,737
2004/05	15,001	14,932	4,003	4,052	19,004	18,984
2005/06	15,214	15,126	4,044	4,103	19,258	19,229
2006/07	15,434	15,326	4,085	4,155	19,519	19,481
2007/08	15,654	15,525	4,127	4,206	19,781	19,731
2008/09	15,873	15,723	4,168	4,258	20,041	19,981
2009/10	16,090	15,921	4,210	4,309	20,300	20,230
2010/11	16,345	16,152	4,258	4,369	20,603	20,521
2011/12	16,543	16,331	4,296	4,416	20,839	20,747
2012/13	16,745	16,515	4,334	4,463	21,079	20,978
2013/14	16,953	16,703	4,373	4,512	21,326	21,215
2014/15	17,174	16,904	4,415	4,564	21,589	21,468
2015/16	17,400	17,109	4,458	4,617	21,858	21,726
2016/17	17,623	17,311	4,500	4,670	22,123	21,981
2017/18	17,851	17,518	4,544	4,724	22,395	22,242
2018/19	18,085	17,731	4,588	4,779	22,673	22,510
2019/20	18,324	17,948	4,633	4,835	22,957	22,783
2020/21	18,559	18,161	4,677	4,890	23,236	23,051
2021/22	18,800	18,379	4,723	4,947	23,523	23,326
2022/23	19,045	18,602	4,770	5,005	23,815	23,607
2023/24	19,297	18,830	4,818	5,064	24,115	23,694
2024/25	19,554	19,063	4,866	5,125	24,420	24,188

Table 10.3 provides the final industrial sector forecast before Power Smart with adjustments for assumed rate impacts and for the anticipated closure of the High Valley Copper operations over fiscal years 2008/09 and 2009/10. In addition, the forecast load has been adjusted to reflect actual sales for the first six months of 2004/05. This has increased industrial distribution sales by 71 GWh, industrial transmission sales by 349 GWh and total industrial sales by 420 GWh for 2004/05 above the regression model based estimate. This unexpected increase in the industrial load suggests the possibility that no rate impact has been experienced for the industrial load for the first six months of 2004/05.

The rate impacts assume: (1) that there is an 8.9% nominal increase with 2% inflation in each of 2004/05, 2005/06 and 2006/07 which translates to a 2.9% real price increase and (2) that prices are constant in real terms in subsequent years. A price elasticity of -0.28 is used, based on an econometric analysis of

BC Hydro's industrial sales. The High Valley Copper impact assumes that consumption will be reduced by about one-half for each of the two years of the closure but that there will be some remaining load for reclamation efforts. The maximum likelihood version of Model 2 is used as the base for the reasons outlined in the appendix.

Table 10.3. Forecast Industrial Sales with Rate Impacts and Highland Valley Closure Before Power Smart (GWh) Model 2

Year	Distrib-ution ML	Trans-mission ML	Indus-trial ML
1994/95	3,740	13,347	17,087
1995/96	3,682	13,948	17,630
1996/97	3,834	13,613	17,447
1997/98	3,786	12,553	16,339
1998/99	3,820	14,257	18,077
1999/00	3,828	14,062	17,890
2000/01	3,627	15,052	18,579
2001/02	3,884	13,855	17,739
2002/03	4,046	14,550	18,596
2003/04	3,918	14,819	18,737
2004/05	4,090	15,160	19,250
2005/06	4,150	15,323	19,473
2006/07	4,181	15,442	19,622
2007/08	4,212	15,559	19,771
2008/09	4,243	15,675	19,919
2009/10	4,274	15,337	19,612
2010/11	4,334	15,566	19,899
2011/12	4,380	15,330	19,711
2012/13	4,427	15,513	19,939
2013/14	4,475	15,699	20,176
2014/15	4,527	15,899	20,426
2015/16	4,580	16,102	20,682
2016/17	4,632	16,302	20,936
2017/18	4,686	16,508	21,193
2018/19	4,740	16,719	21,459
2019/20	4,796	16,934	21,729
2020/21	4,850	17,146	21,996
2021/22	4,907	17,362	22,268
2022/23*	4,964	17,583	22,550
2023/24	5,023	17,809	22,830
2024/25	5,083	18,040	23,123

10.5. Forecast Sales by Sector

Table 10.4 summarises the forecast load by industrial sector. The maximum likelihood forecasts for transmission voltage and distribution voltage customers presented above form the basis of the forecast. Strong medium term growth in mining is due, in part, to the relatively depressed level of sales in 2003/04. As these sectors recover to their medium-term growth trends, sales will increase significantly above their 2003/04 levels. The wood sector experienced strong growth in 2002/03 and 2003/04, but this is unlikely to be sustainable in the medium term as most facilities are working near capacity. Sales to pulp and paper companies are expected to be strong through the current fiscal year, but then are expected to be relatively flat, due to capacity constraints. Sales to the chemical producers and other transmission voltage customers are expected to be essentially flat over the medium term. Distribution sales should be moderately strong over the medium term.

Table 10.4. Industrial Sales by Sector Before Power Smart (GWh) Model 2

	Transmission Voltage Customers						Distrib-ution	
	Metal Mines	Coal Mines	Wood	Paper	Chem-ical	Other Trans-mision Rate	All Sectors[1]	Total Sales
Actual								
1998/99	2,006	574	765	8,501	1,685	727	3,820	18,077
1999/00	1,619	558	826	8,685	1,710	663	3,828	17,890
2000/01	1,996	547	892	8,937	1,724	856	3,627	18,679
2001/02	1,952	554	885	7,957	1,626	880	3,884	17,739
2002/03	1,873	516	928	8,534	1,798	902	4,046	18,596
2003/04	1,906	467	937	8,785	1,787	950	3,918	18,737
Forecast								
2004/05	2,064	500	982	8,815	1,841	958	4,090	19,250
2005/06	2,345	532	934	8,755	1,805	952	4,150	19,473
2006/07	2,398	538	935	8,812	1,806	953	4,181	19,623
2007/08	2,575	555	920	8,771	1,797	942	4,212	19,772
2008/09	2,610	603	920	8,820	1,782	940	4,243	19,918
2009/10	2,432	592	910	8,704	1,769	931	4,274	19,612
2010/11	2,196	622	961	8,948	1,859	979	4,334	19,899
2011/12	2,221	632	952	8,711	1,848	967	4,380	19,711
2012/13	2,291	638	961	8,784	1,863	975	4,427	19,939
2013/14	2,411	641	968	8,828	1,873	980	4,475	20,176
2014/15	2,440	652	981	8,945	1,888	993	4,527	20,426
2015/16	2,470	664	994	9,065	1,903	1,006	4,580	20,682
2016/17	2,499	676	1,007	9,184	1,918	1,020	4,632	20,936
2017/18	2,529	688	1,020	9,304	1,933	1,033	4,686	21,193
2018/19	2,560	700	1,034	9,429	1,949	1,047	4,740	21,459
2019/20	2,591	713	1,048	9,556	1,965	1,060	4,796	21,729
2020/21	2,622	726	1,062	9,681	1,981	1,074	4,850	21,996
2021/22	2,653	739	1,076	98,09	1,996	1,088	4,907	22,268
2022/23	2,686	752	1,091	9,941	2,013	1,103	4,964	22,550
2023/24	2,718	765	1,105	10,073	2,029	1,117	5,023	22,830
2024/25	2,752	779	1,121	10,210	2,046	1,132	5,083	23,123
Growth Rates,								
5 years: 98/99 to 03/04	-1.0%	-4.0%	4.1%	0.7%	1.2%	5.5%	0.5%	0.7%
5 years 03/04 to 08/09	6.4%	5.1%	-0.5%	0.0%	-0.2%	-0.3%	1.6%	1.1%
10 years 03/04 to 14/15	2.4%	3.2%	0.33%	0.1%	0.5%	0.5%	1.4%	0.8%
21 years 03/04 to 24/25	1.8%	2.5%	0.86%	0.7%	0.7%	0.8%	1.3%	1.0%

Notes: 1. Excluding distribution rate transmission voltage (DRTV)

10.6. Risks and Uncertainties

Beyond the general economic risk of higher or lower than economic growth assumptions materializing, a significant risk to the industrial forecast pertains to discrete one time changes in sales to the base metal mining and pulp and paper sectors. Specifically, risks not represented in the forecast relate to large one-time additions or contractions of load as a result of new investment, strikes or closure of major facilities. Because it is difficult to assess the likelihood of these events, the approach has been to relate the industrial load to GDP rather than attempt to forecast these individual discrete events. However, as it relates to one large mining customer, based on public statements of intent to decommission beginning in 2007/08 made earlier in the year, BC Hydro has reduced this load to reflect this discrete event.

11 Peak Forecast

11.1 Introduction

Characteristics:

BC Hydro's peak demand is defined as the expected maximum amount of electricity consumed in a single hour under an average coldest day assumption established as the design temperature. BC Hydro is a winter peaking utility because the system has a larger share of heating load than summer air conditioning load. The distribution peak is the most sensitive to temperature. The transmission peak demand is considered to be responsive to external market conditions and changes in demands for BC's key industrial commodities such as wood, pulp and paper and mining.

Trends:

The peak demand is quite variable to temperature. Last winter, BC Hydro reached an all time record peak which was recorded at 9,619 MW for the Domestic System on January 5th 2004. The daily average temperature for the peak day was -7.1°C. Prior to last winter, BC Hydro's actual peak occurred at temperatures that were much milder. For example, in the winter of 2002/03, the peak was recorded at 8,481MW on December 18th 2002 which had a daily average temperature of 5.3°C. The peak recorded in 2004 and eight years ago were the last two times in the past 10 years that BC Hydro's peak occurred at cold temperatures close to its average coldest day design temperature.

Peak Weather Adjustments:

Since temperature creates most of the variability in the peak demand, the peak forecast is prepared on a weather normalized basis to a design temperature. In addition, the actual peak is adjusted back to the design temperature in order to determine: (i) the growth in peak independent of weather impacts; (ii) the variance in the forecast independent of weather impacts, and (iii) the historical weather adjusted peak anchor value. The anchor value is the previous year's actual peak adjusted for variations in temperature from the design temperature.

In this year's forecast, BC Hydro has re-established its design temperature based on an average of the coldest daily average temperature using the most recent 30 years of weather data. Using the most recent 30 years of temperature is consistent with British Columbia Utilities Commission direction in the VIGP decision and reduces the design temperature from -6.8 °C to -5.3 °C for the System. For VI, the design temperature is reduced from -4.4 °C to -3.6 °C. In addition to changing the design temperature, BC Hydro has also incorporated the impact of the increase in the peak sensitivity to temperature based on last winter's cold temperature and peak data. The impact of last year's cold winter experience is reflected in the regional and system weather-adjusted peak values for fiscal 2003/04. Historical information needs to be re-calibrated to the new design temperatures, so historical growth rates using the new design temperature are not yet available.

Drivers:

BC Hydro's peak forecast is based on the peak demands from its distribution, transmission and wholesales customers including other utilities such as Fortis BC. The distribution peak forecast is prepared for 15 distribution planning areas which are aggregated into four BC Hydro planning regions (i.e. Lower Mainland, Vancouver Island, South Interior and Northern Region). The distribution peak

forecasts are based on local economic drivers including employment and housing starts.

Export market conditions, world demand for BC's industrial commodities and domestic supply and demand for BC's raw industrial products impact BC Hydro's large transmission customers' peak demand for electricity.

Forecast:

The 2004 Domestic system peak forecast for 2004/05 with Power Smart is 9,656 MW. This represents a 2.4% increase from the weather-adjusted 2003/04 Domestic system peak of 9,431 MW for 2003/04. Compared to last year's forecast for 2004/05, this year's forecast with Power Smart is 292 MW higher. The increase in the forecast peak reflects a re-calibration of load sensitivities to the previous year's cold winter temperature impact. As well, this year's forecast reflects a recovery in the transmission peak demand by 65 MW, which is 3.4% higher than last year's forecast for 2004/05 including Power Smart.

With the record peak of 9,619 MW in January 2004, the peak increased in one year by over 1,100 MW compared to the fiscal 2003 peak recorded for December 2002 at 8,481 MW. After accounting for the weather adjustments to the new design temperature of -5.3 $^{\circ}$C, the level of the distribution peak forecast has increased due the impact of last year's cold temperatures on the peak.

The Domestic Peak forecast, including the impacts of Power Smart, is expected to grow from 9,656 in 2004/05 to 9,975 MW in 2008/09 or an annual increase by 1.1%, then to 10,726 MW in 2014/15 or an annual increase by 1.2%, and finally increase to 12,484 MW in 2024/25. This is an annual increase of 1.3% over the 21 years of the forecast. These growth rates represent the increases in the demands the total system's distribution and transmission peak demands including transmission losses.

In the remainder of this chapter, the peak forecast methodology is described, the distribution peak forecast for the various distribution planning areas is presented, the regional distribution and transmission peak forecasts are described, the weather normalization for last year winter is discussed, the total regional and system peak forecasts are presented and 2004 total system peak is provided.

Peak Forecast Method

The peak forecast method is a bottom up driven process that has four main steps: (i) weather-normalised distribution peaks are prepared for four regions as well as the system, (ii) a distribution peak forecast guideline is prepared for 15 planning areas, (iii) a long-term substation peak forecast is prepared for each substation, (iv) regional total peak forecasts and a system peak forecast are prepared.

The method assembles information in a staged process, as users both internal and external to BC Hydro require disaggregated peak forecast information. The four main elements of the forecast process are outlined in figure 11.1. The figure also shows the various intermediate inputs used in developing various peak forecasts at the each stage. Each of these four steps is discussed below.

(1) Weather Normalisation

From the actual recorded substation peaks, a weather-normalised peak is prepared for each substation in the various planning areas using a linear regression model and substation peak data and local weather station temperatures. The total weather-normalised substation peak in each planning area is aggregated from bottom up starting from the15 planning areas into four service regions totals for the regions of the Lower Mainland, Northern Region, South Interior and Vancouver Island.

BC Hydro also uses a top down daily peak model and weather normalization procedure to produce weather normalized peaks for the historical recorded peak. From the procedure, weather normalized peaks are prepared for Vancouver Island and the total System. The daily peak model uses hourly load data and relates them to temperatures in a cubic equation. The model and procedure is discussed in detail in Appendix 4.

After the results of the top down weather-adjusted peaks are determined, the System and distribution peak anchor points are compared to anchor points based on the bottom up substation peak data. In the final analysis a blending or averaging of the top down and bottom up weather-adjusted peaks are used to establish the anchor points for each region and the total system.

Using weather-adjusted peaks from two approaches reduces the risk of relying upon one method for weather adjustments.

(2) Distribution Peak Guideline Model

The peak forecast process starts by developing a non-coincident distribution peak forecast for 15 distribution planning areas including: Vancouver Island North, Central, South; Southern Interior Thompson/Shuswap and Okanagan/Thompson, Northern Region West, Central and East and seven Lower Mainland areas. The forecast is prepared using a model that incorporates: (1) local area economic forecasts such as employment forecast, (2) forecasts of housing starts and housing stock, (3) account forecasts by heating type and dwelling type, and (4) the total sum of the weather normalised substation peak of each substation serving the planning area.

The distribution peak guideline forecast provides a guideline for the total growth for the sum total of each substation that serves customers in that planning area over an 11 year forecast period.

(3) Substation Peak Forecast

A discrete substation peak forecast is prepared for each of BC Hydro's 220 substations that reflects trends in historic weather adjusted substation growth rate, load transfers between substations and information on new discrete load additions at the substation level in addition to the distribution peak guideline forecast.

(4) Regional Peak and System Peak Forecasts

For each of the four service regions, a total regional peak forecast is prepared as the sum of the region's distribution peak, transmission peak and wholesale peak sales to other utilities.

To prepare the regional distribution peak forecasts, the long-term substation peak forecasts and the distribution peak guideline forecasts are averaged and aggregated from the 15 planning areas into four regional distribution peak

forecasts. Averaging the substation and guideline forecast reduces the risk of relying upon one forecast method and incorporates the information on new larger developments that impact individual substations.

After the two forecasts are averaged and aggregated into four regional forecasts, regional coincident factors and power factors are applied to convert the non-coincident peak forecasts to regional distribution coincident forecasts. Coincidence factors are applied to account for load diversity (i.e. differences in the timing of the total distribution substation peak relative to the region's distribution peak). Rate impacts and capacity savings from Power Smart are incorporated at the regional distribution peak level for each of the four service regions. Included in the regional distribution peak forecast are distribution losses because the substation and guideline forecasts represent the total peaks at substation level.

To prepare the regional transmission peak forecasts, forecasts are prepared for each transmission account over the short to medium-term on a non-coincident basis. The individual account forecasts are based on 3rd party industrial sector studies, customer information from BC Hydro's key account managers and an econometric time series model using historical metered peaks.

After the individual transmission account forecasts are finalized, the 135 account forecasts are aggregated into the four regions. Coincident factors and power factors are applied at the regional total level to convert the total non-coincident peaks forecast to total regional coincident transmission peak forecasts. Rate impacts and capacity savings from Power Smart at the regional transmission level are incorporated into the transmission peak forecast for each service region.

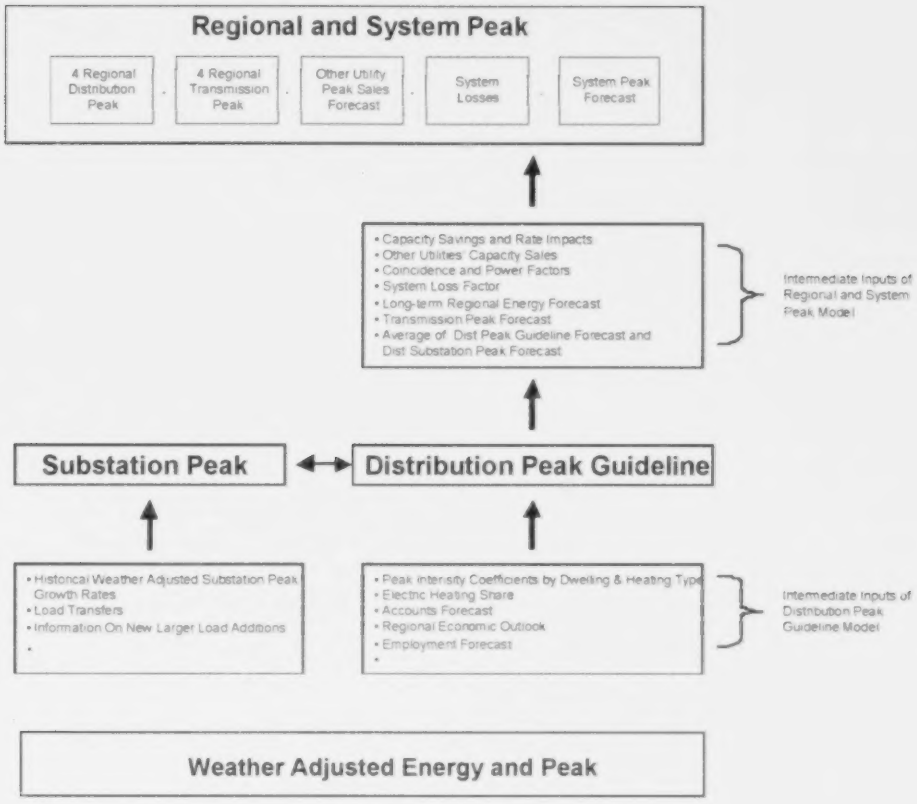
For each of the four service regions, the total regional peak forecast is prepared as the sum of the regional distribution and transmission peak forecast and applicable wholesale customer peak sales. The wholesale peak sales are based on treaty arrangements as the case of Seattle City Light or based on nominations for peak demand under approved rates such as the case for Fortis BC.

A total system peak forecast is prepared as the sum of the total distribution peak, total transmission peak, total wholesale peak sales and total transmission losses.

The total distribution peak is the weighted sum of the regional distribution peaks where the system distribution coincident factors are the weights. The total transmission peak is also the weighted sum of the regional transmission peak factors. Separate coincidence factors, for distribution and transmission, as the weights, are applied in summing up the regional peaks to account for load diversity between the region and the total system peak. The coincidence factors are based on analyses of historical data.

A system transmission loss factor of 8.7%, for the hour of the peak, is applied to the domestic distribution and transmission peak forecasts. The loss factor is based on transmission load flow studies.

Figure 11.1. Peak Forecast Methodology Overview


Regional and System Peak
4 Regional Distribution Peak
4 Regional Transmission Peak
Other Utility Peak Sales Forecast
System Losses
System Peak Forecast
• Capacity Savings and Rate Impacts
• Other Utilities' Capacity Sales
• Coincidence and Power Factors
• System Loss Factor
• Long-term Regional Energy Forecast
• Transmission Peak Forecast
• Average of Dist Peak Guideline Forecast and Dist Substation Peak Forecast
Intermediate Inputs of Regional and System Peak Model
Substation Peak
Distribution Peak Guideline
• Historical Weather Adjusted Substation Peak Growth Rates
• Load Transfers
• Information On New Larger Load Additions
• Peak Intensity Coefficients by Dwelling & Heating Type
• Electric Heating Share
• Accounts Forecast
• Regional Economic Outlook
• Employment Forecast
Intermediate Inputs of Distribution Peak Guideline Model
Weather Adjusted Energy and Peak

11.2.1. Distribution Peak Forecasts

At the distribution level, electricity demand is closely linked to the forecast of the local economy, as well the historical trends of distribution load growth. As such, the regional economic outlook is one of the primary inputs into distribution peak demand forecasts. BC Hydro obtains an economic forecast from B.C. Statistics, external consultants and the Greater Vancouver Regional District.

As described in the peak forecast methodology overview, the distribution peak forecast is based on a distribution peak guideline forecast for each of the 15 planning areas. The distribution peak guideline forecast is prepared using an econometric model. The forecast provides a guideline for the total non-coincident (MVA) growth for all of the substations serving distribution customers in that area.

The basic framework of the distribution peak forecast guideline model is given by:

(11.1) Peak = Stock X Electric Intensity per unit of Stock

The two main stock forecasts, used in the model, are the forecasts of employment and the number of residential customer accounts, which is driven by housing starts. The residential account forecast is also used to develop the residential sales forecast. The employment forecast is based on third party information.

The electric intensity per unit of stock is in the form of the peak load per unit of housing (kW per account) for the residential sector. This intensity varies by heating type and dwelling type. For the general rate class, the peak per unit of sales (kW per kWh) is the intensity factor.

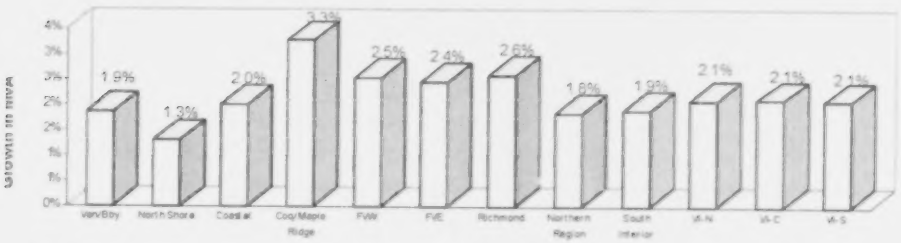
Figure 11.2 shows the average annual growth rates, over the 11 year forecast period for the various planning areas, according to this year's distribution peak guideline forecast.

In the short-term, this year's total guideline forecast growth projection is 2.71% compared to last year's growth projection of 1.9% for 2004/05 before rate impacts. Areas that are expected to grow stronger in 2004/05 include the Fraser Valley East and the Coastal area, which includes the Whistler and Squamish districts.

The guideline forecast reflects changes in the anticipated growth in drivers of the forecast compared to last year's forecast. This includes growth in projected number of residential accounts as account growth continues to be fuelled by the low interest rate environment. Short-term employment forecast, another driver of the forecast, is projected to be relatively strong at 1.8% increase for 2004, but not as strong as the gains made between 2002 and 2003 at 2.5%.

Over the 11-year period, the average growth rate in the total peak guideline forecast is 1.8%, which is slightly below last year's forecast average growth of 2.0% as the long-term impacts of employment growth from the Olympics is expected to be lower in the post-Olympic years.

Figure 11.2. Distribution Peak Forecast Guideline Before Power Smart – Average Annual MVA Growth (2003/04 to 2014/15)



Notes:

1. Coastal includes Squamish, Whistler, Sunshine Coast and Powell River. 2. Fraser Valley West includes Richmond, Delta, Surrey and Langley. 3. VI-S is Vancouver Island South, VI - C is Vancouver Island Central which includes Gulf Islands and VI - N is Vancouver Island North.

Regional Distribution Peak Forecast

BC Hydro forecasts a distribution peak for each the four major regions of Vancouver Island, Lower Mainland, Northern Region and South Interior. The

regional distribution peak forecast is based on an average of the distribution guideline peak forecast and the long-term substation peak forecast. In the regional and system peak model, the forecasts are averaged and aggregated into four regions from 15 planning areas. Regional power factors and coincidence factors are applied to produce a coincident distribution peak forecast (MW) for each of the major regions.

Table 11.1 shows the non-coincident (MVA) and coincident distribution peak (MW) forecast before Power Smart for each region. The first 11 years of the forecast is based on the average of the two peak forecasts. The second 10 years of the regional distribution peak forecast is derived using the growth rate in the distribution energy sales.

Compared to last year's forecast for 2004/05, this year's forecast by region before Power Smart is above last year's forecast. However, this year's anchor points or weather-adjusted peaks are higher as they reflect the recalibration to the cold temperature data. BC Hydro has re-calibrated its top down peak model with last year's peak and cold temperature data to reflect changes to the distribution sector's sensitivity of temperature to peak. The results of the weather-adjusted peaks by region and for the System are discussed in section11.3.

On a regional basis, the Lower Mainland continues to show the strongest increase in the projected growth between the two years. Last year's projected growth was 2.6% and this year's continues at 2.3%. This reflects the continued strong growth in demand for goods and services and exports of finished products. As well, some areas in the total Lower Mainland such as the Coastal area are expected to have stronger growth this year compared to last year. The short term reduction is due to the requested rate increase on peak.demand.

Table 11.1. Regional Non-Coincident and Coincident Distribution Peaks Forecast Before Power Smart

	Lower Mainland		Vancouver Island		South Interior		Northern Region	
	Non-Coinc. Peak (MVA)	Coinc. Peak (MW)	Non-Coinc. Peak (MVA)	Coinc. Peak (MW)	Non-Coinc. Peak (MVA)	Coinc. Peak (MW)	Non-Coinc. Peak (MVA)	Coinc. Peak (MW)
Actual								
2003/04	4,318	3,935	1,849	1,703	932	841	723	645
Weather-Adjusted Actual								
2003/04	4,258	3,826	1,803	1,660	913	824	725	647
Forecast (Weather-Adjusted)								
2004/05	4,395	3,948	1,833	1,688	934	843	736	657
2005/06	4,482	4,026	1,852	1,705	943	850	741	662
2006/07	4,575	4,110	1,882	1,733	956	862	751	671
2007/08	4,674	4,199	1,919	1,767	970	875	762	680
2008/09	4,783	4,297	1,958	1,803	985	889	773	690
2009/10	4,877	4,381	1,998	1,840	1,001	903	783	700
2010/11	4,950	4,447	2,037	1,875	1,013	914	794	709
2011/12	5,023	4,513	2,073	1,909	1,026	925	805	719
2012/13	5,099	4,581	2,108	1,941	1,039	937	816	729
2013/14	5,180	4,653	2,141	1,971	1,052	949	828	739
2014/15	5,258	4,723	2,173	2,001	1,065	961	839	749
2015/16	5,351	4,807	2,210	2,035	1,081	976	848	757
2016/17	5,445	4,892	2,248	2,070	1,098	991	858	766
2017/18	5,542	4,979	2,286	2,105	1,115	1,006	867	774
2018/19	5,640	5,066	2,325	2,141	1,132	1,021	876	782
2019/20	5,739	5,156	2,365	2,178	1,150	1,037	886	791
2020/21	5,841	5,247	2,405	2,215	1,167	1,053	895	799
2021/22	5,944	5,340	2,446	2,252	1,185	1,069	905	808
2022/23	6,049	5,434	2,488	2,291	1,204	1,086	915	817
2023/24	6,156	5,530	2,531	2,330	1,222	1,103	924	825
2024/25	6,264	5,628	2,574	2,370	1,241	1,120	934	834
Growth Rates (Weather Adjusted)								
5 years 03/04 to 08/09	2.3%	2.3%	1.7%	1.7%	1.5%	1.5%	1.3%	1.3%
11 years 03/04 to 14/15	1.9%	1.9%	1.7%	1.7%	1.4%	1.4%	1.3%	1.3%
21years 03/04 to 24/25	1.9%	1.9%	1.7%	1.7%	1.5%	1.5%	1.2%	1.2%

Notes:

1. Distribution peak forecast based on average of Substation forecast and Distribution Peak Guideline Forecast
2. Growth rates based on weather adjusted peaks.

11.2.2. Regional Distribution Peak Forecast

The transmission peak forecast is prepared on a customer-by-customer basis. Information from BC Hydro's key account managers, historical billing data used in an econometric model for the larger accounts, and 3rd party reports on BC's major industries are the key sources of information used to establish transmission forecast over the first 11 years. The individual transmission peak forecast is prepared on a non-coincident basis. The forecasts for each account are then aggregated into four regional forecasts and regional coincidence and power factors are applied to establish the regional coincident transmission peak forecasts.

Over the first 11 years of the forecast period, the transmission forecasts are scaled to ensure the annual growth in the transmission peak forecast is consistent with the annual growth in the total industrial energy transmission forecast. This scaling preserves the load factor for each customer. The industrial energy transmission forecast is based on a regression analysis where GDP is the key driver in the forecast.

For the last 10 years of the forecast period, the transmission peak forecast for each region is derived using the growth rate in the transmission energy forecast in each region.

Table 11.2 shows the transmission peak forecast before Power Smart for each region.

The forecast reflects the anticipated closure of Highland Valley Copper Mine which accounts for the negative annual growth rates in the Southern Interior. In the medium-term, the increase in the transmission peak requirements in the Northern Region reflects the anticipated recovery in BC's mining sector.

The non-coincident transmission peak forecast for Vancouver Island is expected to decline in the short-term from 625 MW in 2003/04 to 588 MW to 2004/05. The decline reflects that expectation that higher exchange rate and softening of lumber prices for wood may impact some smaller transmission customers over the short-term. The recovery in the pulp and paper sector is expected to develop gradually.

The short-term transmission forecast, on a coincidence basis, shows an increase in from 440 MW in 2003/04 to 470 MW in 2004/05. The increase in the forecast on a coincidence basis and decrease in the forecast on non-coincidence basis reflects the fact that last year's actual transmission coincidence factor of 0.70, (derived as the ratio of coincidence transmission peak (440 MW) to non-coincident peak (625 MW)) was lower than expected. Historically, the five year average transmission coincidence factor is about 0.80, which is assumed in the forecast. BC Hydro has maintained the assumption because this one-year change is not conclusive evidence in the data to suggest a deviation from the historical trend.

Table 11.2. Regional Non-Coincident and Coincident Transmission Peaks Forecast Before Power Smart

	Lower Mainland		Vancouver Island		South Interior		Northern Region	
	Non-Coinc. Peak (MW)	Coinc. Peak (MW)	Non-Coinc. Peak (MW)	Coinc. Peak (MW)	Non-Coinc. Peak (MW)	Coinc. Peak (MW)	Non-Coinc. Peak (MW)	Coinc. Peak (MW)
Actual								
2003/04	634	402	625	440	334	255	1012	753
Forecast								
2004/05	656	459	588	470	335	256	955	692
2005/06	641	449	578	462	327	250	956	693
2006/07	651	456	581	465	329	251	966	700
2007/08	648	453	576	461	327	250	973	705
2008/09	649	454	577	462	266	203	1,067	773
2009/10	647	453	572	458	263	202	1,032	748
2010/11	664	465	602	482	222	170	1,085	786
2011/12	643	450	595	476	220	168	1,073	777
2012/13	648	454	600	480	221	169	1,097	795
2013/14	651	456	603	483	222	170	1,102	799
2014/15	654	457	606	485	223	171	1,107	802
2015/16	655	459	607	486	223	171	1,109	804
2016/17	657	460	609	487	223	170	1,111	805
2017/18	659	461	612	489	223	171	1,116	809
2018/19	662	463	615	492	223	171	1,121	812
2019/20	663	464	617	493	223	171	1,124	815
2020/21	662	463	615	492	222	170	1,124	814
2021/22	660	462	613	491	220	168	1,222	813
2022/23	663	464	617	494	221	169	1,130	819
2023/24	666	466	621	497	221	169	1,138	825
2024/25	669	468	624	499	222	170	1,147	831
Growth Rates								
5 years 03/04 to 08/09	0.5%	2.5%	-1.6%	1.0%	-4.5%	-4.4%	1.1%	0.5%
11 years 03/04 to 14/15	0.3%	1.2%	-0.3%	0.9%	-3.6%	-3.6%	0.8%	0.6%
21years 03/04 to 24/25	0.3%	0.7%	0.0%	0.6%	-1.9%	-1.9%	0.6%	0.5%

11.3 Weather Normalization

The weather-normalized peak for each substation is based on a weather-normalization procedure that uses a linear regression of winter-metered substation peak load on temperature readings from the weather station closest to each substation. After the regression is completed, a normalized peak for each substation is computed, based on an average coldest temperature, which is defined as the average of the lowest daily average temperature over 30 year period. The temperature data is based on the most recent daily temperatures as provided by Environment Canada for each local weather station. The weather adjusted substation peaks is aggregated from the bottom up from the 15 planning areas into four regions.

Difficulties, however, may hamper a weather-normalized peak from being determined for each substation. These difficulties are related to the recent milder weather conditions, load transfers between stations and load fluctuations in industrial distribution, which impact the recorded peaks. Last year's cold temperatures provided good data based on close to average coldest weather to to most of the substation peaks, which are winter peaking, to calibrate the weather adjustments

BC Hydro also uses a top-down approach to determine the weather-adjusted peak. This approach uses hourly load data and a weather-normalization procedure based on a cubic regression equation as a means to determine the weather-adjusted peak for the total system and for Vancouver Island. The procedure for weather-normalized total system and VI peak using hourly load is described in Appendix 4.

The weather-adjusted peak for Vancouver Island and the System peak, as determined by the top-down approach, are used as a means to validate and reconcile the anchor point for the distribution peak and total system peak based on the bottom up substation weather normalized peak data. The process of reconciling the anchor point from the two approaches to weather normalization occurs in the regional and system peak model. This involves a blending of both approaches to weather normalization. Having both approaches reduces the risk of relying upon any single approach.

Table 11.3 shows the total weather-adjusted peak as determined by the bottom-up approach by aggregating each substation's weather-adjusted peak. The table also presents the weather-adjusted peak used to develop the 2004 forecast and the weather adjusted peaks based on the top down weather normalization procedure.

As a result of this past winter experience of cold day temperature there was an opportunity to recalibrate the weather adjustment for most of the substations As a result there is only a 46 MW difference between the total weather adjusted coincident distribution peak used in the final forecast and the coincident weather adjusted distribution peak based on the bottom up approach using substation data.

Table 11.3. Fiscal 2003/04 Regional and Total Actual and Weather-Adjusted Non-Coincident Distribution Peak

	Top Down Weather Adjusted Peak		Bottom-Up Substation Weather-Adjusted Peak		Weather-Adjusted Base Year for This Years Forecast	
	MVA	MW	MVA	MW	MVA	MW
	Non-Coin.	Coin.	Non-Coin.	Coin.	Non-Coin	Coin
Lower Mainland	4,276	3,842	4,258	3,825	4,258	3,826
Vancouver Island	1,804	1,616	1,760	1,577	1,803	1,660
South Interior	923	791	905	776	913	824
Northern Region	716	605	725	615	725	647
Distribution Peak Total[1]	7,718	6,856	7,648	6,792	7,699	6,838
Transmission Peak Total [2]		1,838		1,838		1,838
Losses [3]		756		751		755
Domestic System Peak		9,450		9,381		9,431

Notes:

1. Total Regional distribution peak is less than the sum of each Regional peak because regional distribution peaks occur at different time relative to system's distribution peak.
2. Transmission Peak includes peak requirements for the City of New Westminster.
3. Losses are not computed on a non-coincident MVA basis but are computed on a coincident basis, as such only the Domestic system coincident peak is provided.

11.4 Total Regional Peak and System Peak Forecast

As previously stated, BC Hydro calculates a regional peak forecast for the regions of Lower Mainland, Vancouver Island, Northern Region and South Interior. The peak forecast in each region is equal to the coincident sum of the regional distribution and transmission peak and applicable wholesale peak loads. In any region, the total regional peak is:

(11.2) $\text{Regional Peak}_{(t)} = \text{Regional Transmission Peak}_t + \text{Regional Distribution Peak}_t + \text{Wholesale Peak}_t$

The regional peak forecast and system peak forecast are developed using BC Hydro's regional and system peak forecast model. The model also incorporates capacity savings, as provided by Power Smart and estimated rate impacts for distribution and transmission peaks.

Tables 11.4 and 11.5 present the total regional and System peak forecasts before and with Power Smart.

Since the total regional peak forecast is computed as a sum, differences between this year's total regional peak forecast growth rates for 2004/05 and last year's are primarily due to changes in the peak demands for the distribution and transmission customers which were discussed previously.

This year's total regional forecasts are higher than last year's because of the re-calibration of the distribution anchor points to last year's peak and cold temperature data.

In addition to the System reaching a record peak, the peak on Vancouver Island reached an all time record peak at 2,193 MW on January 4th 2004 (excluding Gulf Island Loads and including transmission losses) and 2,253 MW (including Gulf Island Load and including transmission losses). The daily average temperature for the day of the peak was -4.7 °C which is only 0.3 °C colder than VI peak design temperature used in last year's forecast.[3]

For 2004/05, the VI peak forecast before Power Smart (excluding transmission losses) for 2004/05 is 2,158 MW is 92 MW above last year's forecast of 2,066 MW for 2004/05. This increase in the forecast reflects a 31 MW increase in the coincidence transmission peak forecast and 62 MW increase in the coincidence distribution peak forecast. This increase reflects the re-calibration of the weather adjusted peak to the increase in the sensitivity of peak compared to last year's forecast as well as the change in the expected drivers of the distribution in last year's forecast compared to this year's forecast.

Tables 11.4 and 11.5 also provide the Domestic Peak forecast before and with Power Smart. BC Hydro's Domestic system peak forecast is the coincident sum of the four region's distribution and transmission peak forecasts, plus wholesales peak loads, plus the total transmission losses. The total System peak forecast is examined in the next section.

[3] The 2003/04 weather adjusted peak or anchor point for this year's forecast is estimated to be 2,240 MW (including transmission losses) or 2,129 MW (excluding transmission losses). Using the most recent 30 years of temperature, the weather adjusted peak is reduced to 2,210 MW and 2,100 MW with and without losses respectively.

Table 11.4. Domestic System and Regional Peak Forecast Before Power Smart

	Lower Mainland	Vancouver Island	Southern Interior	Northern Region	Transmission Losses	Domestic System
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Actual						
2003/04	4,528	2,143	1,468	1,399	757	9,591
Weather-Adjusted Actual						
2003/04	4,429	2,100	1,260	1,401	754	9,431
2004/05	4,608	2,158	1,280	1,350	778	9,721
2005/06	4,677	2,167	1,282	1,355	785	9,813
2006/07	4,768	2,197	1,295	1,372	798	9,974
2007/08	4,856	2,227	1,307	1,386	810	10,128
2008/09	4,955	2,264	1,273	1,464	826	10,322
2009/10	5,039	2,297	1,289	1,448	836	10,444
2010/11	5,117	2,357	1,272	1,496	850	10,621
2011/12	5,169	2,385	1,286	1,497	857	10,717
2012/13	5,242	2,421	1,302	1,524	870	10,877
2013/14	5,318	2,454	1,315	1,539	882	11,021
2014/15	5,390	2,485	1,327	1,552	893	11,161
2015/16	5,476	2,520	1,342	1,562	905	11,317
2016/17	5,563	2,556	1,357	1,572	918	11,475
2017/18	5,652	2,594	1,373	1,584	931	11,640
2018/19	5,743	2,632	1,388	1,595	945	11,808
2019/20	5,835	2,670	1,404	1,607	958	11,976
2020/21	5,926	2,706	1,419	1,615	971	12,136
2021/22	6,018	2,743	1,433	1,622	984	12,298
2022/23	6,115	2,784	1,451	1,637	998	12,480
2023/24	6,214	2,826	1,468	1,651	1,013	12,666
2024/25	6,315	2,869	1,486	1,666	1,028	12,855
Growth Rates (Weather Adjusted)						
5 years 03/04 to 08/09	2.3%	1.5%	0.2%	0.9%	1.8%	1.8%
11 years 03/04 to 14/15	1.8%	1.5%	0.5%	0.9%	1.5%	1.5%
21years 03/04 to 24/25	1.7%	1.5%	0.8%	0.8%	1.5%	1.5%

Notes:

1. Regional peak includes distribution losses but not transmission losses.
2. The domestic system peak is less than the sum of the regional peaks plus transmission losses because regional peaks occur at different times.
3. Lower Mainland peak includes sales to City of New Westminster and firm exports to Seattle City Light.

4. Southern Interior includes sales to Fortis BC Canada.
5. Northern Peak includes integrated system only.
6. Actual peaks are not weather-normalized and peak forecast values are weather-normalized.
7. Growth rates are based on weather-adjusted peaks.

Table 11.5. Domestic System and Regional Peak Forecast With Power Smart

	Lower Mainland	Vancouver Island	Southern Interior	Northern Region	Transmission Losses	Domestic System
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
Actual						
2003/04	4,528	2,143	1,468	1,399	757	9,591
Weather-Adjusted Actual						
2003/04	4,429	2,100	1,260	1,401	754	9,431
Forecast						
2004/05	4,578	2,146	1,275	1,336	772	9,656
2005/06	4,637	2,149	1,274	1,291	774	9,673
2006/07	4,703	2,164	1,279	1,288	781	9,763
2007/08	4,761	2,177	1,280	1,280	787	9,832
2008/09	4,841	2,204	1,241	1,345	798	9,975
2009/10	4,917	2,232	1,254	1,325	806	10,075
2010/11	4,985	2,286	1,234	1,368	818	10,228
2011/12	5,027	2,309	1,245	1,363	824	10,298
2012/13	5,094	2,342	1,259	1,387	835	10,442
2013/14	5,168	2,374	1,272	1,402	847	10,585
2014/15	5,241	2,406	1,285	1,416	858	10,726
2015/16	5,328	2,443	1,300	1,428	873	10,889
2016/17	5,416	2,480	1,316	1,441	884	11,053
2017/18	5,505	2,519	1,332	1,454	898	11,220
2018/19	5,595	2,558	1,348	1,467	911	11,389
2019/20	5,688	2,597	1,364	1,480	925	11,563
2020/21	5,783	2,637	1,381	1,495	939	11,743
2021/22	5,881	2,678	1,399	1,511	954	11,927
2022/23	5,979	2,719	1,416	1,526	969	12,109
2023/24	6,078	2,761	1,433	1,540	983	12,295
2024/25	6,179	2,804	1,451	1,555	999	12,484
Growth Rates (Weather Adjusted)						
5 years 03/04 to 08/09	1.8%	1.0%	-0.3%	-0.8%	1.1%	1.1%
11 years 03/04 to 14/15	1.5%	1.2%	0.2%	0.1%	1.2%	1.2%
21years 03/04 to 24/25	1.6%	1.4%	0.7%	0.5%	1.3%	1.3%

Notes:

1. Regional peak includes distribution losses but not transmission losses.
2. The domestic system peak is less than the sum of the regional peaks plus transmission losses because regional peaks occur at different times.
3. Lower Mainland peak includes sales to City of New Westminster and firm exports to Seattle City Light.

4. Southern Interior includes sales to Fortis BC Canada.
5. Northern Peak includes integrated system only.
6. Actual peaks are not weather-normalized and peak forecast values are weather-normalized.
7. Growth rates are based on weather-adjusted peaks.

11.4.1. 2004 Peak Forecast

This year's peak forecast for 2004/05 is 221 MW higher than last year's forecast before Power Smart. Distribution Peak is 168 MW higher for the current forecast and Transmission Peak is 32 MW higher.

Table 11.6. Actual and Weather-Adjusted and Peak Forecasts Before Power Smart

	Distribution		Transmission	Domestic System Peak	
	Actual Peak	Weather-Adjusted Peak	Peak	Actual Peak	Weather-Adjusted Peak
	MW	MW	MW	MW	MW
Actual					
2003/04	7,004	6,838	1,760[1]	9,619	9,431
Forecast					
2004/05		7,015	1,850		9,721
2005/06		7,122	1,826		9,813
2006/07		7,253	1,843		9,974
2007/08		7,396	1,840		10,128
2008/09		7,551	1,863		10,323
2009/10		7,694	1,832		10,445
2010/11		7,813	1,874		10,621
2011/12		7,932	1,843		10,717
2012/13		8,052	1,869		10,877
2013/14		8,175	1,878		11,022
2014/15		8,295	1,886		11,161
2015/16		8,433	1,890		11,317
2016/17		8,574	1,894		11,475
2017/18		8,718	1,901		11,641
2018/19		8,863	1,908		11,808
2019/20		9,011	1,914		11,976
2020/21		9,162	1,910		12,137
2021/22		9,315	1,904		12,298
2022/23		9,470	1,916		12,481
2023/24		9,629	1,927		12,666
2024/25		9,789	1,939		12,855
Growth Rates					
5 years 03/04 to 08/09		2.0%	1.2%		1.8%
11 years 03/04 to 14/15		1.8%	0.6%		1.5%
21years 03/04 to 24/25		1.7%	0.5%		1.5%

Notes:

1. On the day of the System peak, there was 20 MW of curtailment in the transmission peak. As such, the actual transmission peak is 1740 MW but reported as 1760 MW.

2. Growth rates for the total distribution peak and Domestic peak are reported on a weather-adjusted basis.

Table 11.7. Actual and Weather-Adjusted and Peak Forecasts With Power Smart

	Distribution		Transmission	Domestic System Peak	
	Actual Peak	Weather-Adjusted Peak	Peak	Actual Peak	Weather-Adjusted Peak
	MW	MW	MW	MW	MW
Actual					
2003/04	7,004	6,838	1,760[1]	9,619	9,431
Forecast					
2004/05		6,973	1,833		9,656
2005/06		7,061	1,759		9,673
2006/07		7,161	1,740		9,763
2007/08		7,269	1,695		9,832
2008/09		7,401	1,694		9,975
2009/10		7,530	1,655		10,075
2010/11		7,636	1,689		10,228
2011/12		7,740	1,649		10,298
2012/13		7,851	1,670		10,442
2013/14		7,972	1,679		10,585
2014/15		8,092	1,688		10,726
2015/16		8,231	1,697		10,889
2016/17		8,371	1,707		11,053
2017/18		8,514	1,718		11,220
2018/19		8,658	1,729		11,389
2019/20		8,805	1,740		11,563
2020/21		8,958	1,751		11,743
2021/22		9,115	1,763		11,927
2022/23		9,270	1,774		12,109
2023/24		9,428	1,786		12,295
2024/25		9,589	1,798		12,484
Growth Rates					
5 years 03/04 to 08/09		1.6%	-0.8%		1.1%
11 years 03/04 to 14/15		1.5%	-0.4%		1.2%
21years 03/04 to 24/25		1.6%	0.1%		1.3%

Notes:

1. On the day of the System peak, there was 20 MW of curtailment in the transmission peak. As such, the actual transmission peak is 1740 MW but reported as 1760 MW.

2. Growth rates for the total distribution peak and Domestic peak are reported on a weather-adjusted basis.

Transmission Total Peak Forecast

The forecast of the transmission peak for the winter of 2004/05 is 65 MW or 3.4% above last year's forecasts with Power Smart on a system coincident basis. The difference in the transmission peak forecast before Power Smart between this year's and last year's forecast for 2004/05 is 32 MW.

The increase in the 2004 forecast is attributed to the increase in the industrial activity last year. The increase in demand for commodities and recovery of prices for copper and pulp and paper led to modest gains in 2003 as the non-coincident peak increased by 1% between 2002/03 and 2003/04. As such this year's non-coincident peak forecast has increased compared to last year forecasts. Accounting for these two factors has lead to an increase in the forecast compared to last year's forecasts both on a coincident and non-coincident basis for F2004/05.

In addition, this year's forecast has been adjusted by a load factor to maintain with the growth in the industrial transmission energy forecast. The industrial transmission energy forecast is higher this year compared to last year because the increase in the GDP forecast. This has increased the level of the forecast compared to last year.

11.4.3. Distribution Total Peak Forecast

The forecast of the distribution peak for the winter of 2004/05 is 201 MW above last year's forecasts with Power Smart and 168 MW before Power Smart on a system coincident basis. This increase reflects the impact of the higher peak sensitivity to temperature and the remainder of the difference reflects the changes in the anticipated drivers of the peak forecast for this year's forecast compared to last year's forecast for 2004/05. This year's distribution peak forecast is above last years forecast. This is due to the continued anticipated strong growth in the residential accounts forecast, the increase in the employment forecast in the medium-term due to the Olympics, and an increase in the overall distribution energy forecast in the long-term.

12 Power Smart and the Conservation Potential Review Study

12.1. Conservation Potential Review

BC Hydro made a significant investment in conservation through its Power Smart program in the 1989 to 1997 period. Investments of this type are made by utilities to defer capital investments in distribution and transmission infrastructure, and to defer the need to build generation or purchase power. Investments by the utility and its customers are made in energy-efficient equipment and process improvements where both the utility ratepayers and the customers are better off in the long term. The first phase of Power Smart resulted in energy savings by 1998/99 of approximately 2,500 GWh per year.

During the early years of Power Smart, a Conservation Potential Review (CPR, 1994) was undertaken to assess the potential for electricity savings under various scenarios. As the current phase of Power Smart was ramping up, plans were based on outputs from the first CPR, and the experience and results of the first decade of investment. A second CPR was commissioned and was completed in 2003. The study had the following objectives:

- To provide BC Hydro's Power Smart program planners with an updated assessment of the remaining electricity efficiency potential in B.C. as a basis for designing new initiatives or rates;
- To estimate the potential contribution of Power Smart efficiency programs to the reduction of BC Hydro's peak capacity requirements; and
- To identify additional technologies that could be "fast tracked" to provide further savings over the study period.

The Review confirms that significant cost-effective electricity efficiency improvements do exist in every sector in BC Hydro's service area. Table 12.1 summarizes the total energy savings potential under the conditions defined in the study as "Economic" and "Achievable," as compared with the Reference Case. Table 12.2 summarizes the demand implications of the projections.

Table 12.1 Forecast Summary – Total BC Hydro Service Area Annual Electricity Consumption and Potential Savings*

Annual Electricity Consumption (GWh per year) All Sectors						Potential Annual Savings (GWh per year)		
	Base Year	Reference Case	Economic	Achievable		Economic	Achievable	
				Most Likely	Upper		Most Likely	Upper
2000/01	47,521	47,521						
2005/06		49,739	42,513	48,509	47,652	7,226	1,231	2,087
2010/11		52,663	41,856	49,208	47,406	10,807	3,455	5,257
2015/16		54,729	42,267	48,894	46,507	12,462	5,835	8,222

* Line losses are not included.

Table 12.2. Forecast Summary – Total BC Hydro Service Area
Demand Implications of Economic and Achievable Forecasts*

(High-demand period, winter weekdays from 6 AM to 10 PM, December and January)

Average On-peak Demand (MW) All Sectors						Potential On-peak Demand Savings (MW)		
	Base Year	Reference Case	Economic	Achievable		Economic	Achievable	
				Most Likely	Upper		Most Likely	Upper
2000/01	4,912	7,146						
2005/06		7,522	6,400	7,345	7,220	1,122	177	302
2010/11		7,982	6,349	7,491	7,228	1,633	491	754
2015/16		8,342	6,462	7,501	7,138	1,880	841	1,204

* Includes line losses at seven per cent. (This includes distribution losses of four per cent and area transmission losses of three per cent).

12.2. Power Smart 10-Year Plan

Power Smart was launched by BC Hydro in 1989/90 with the primary aim of achieving significant energy savings from existing and new customers, thus deferring the need for new generation supply.

By 2000, Power Smart yielded 2,500 GWh per year in energy savings at a cost of $338.4 million. These savings are equivalent to meeting the energy needs of a community the size of Surrey (250,000 homes), and deferring the need for 500 MW of generation. Over 700,000 customers have participated in Power Smart thus far, resulting in savings of more than $1.1 billion on their electricity bills. Savings have also resulted in the reduction and/or avoidance of more than 1.25 million tonnes of greenhouse gases per year.

The provincial government in its 2002 energy policy clearly elevates the importance of conservation and energy efficiency in the context of meeting B.C.'s future energy needs. Power Smart is again well positioned to play a strategic role in BC Hydro's continuing efforts to deliver competitive integrated energy solutions to its customers in an environmentally and socially responsible manner.

12.2.1. 10-Year Power Smart Plan

Based on the process and the outputs from the 2002 Conservation Potential Review, a Power Smart 10-Year Plan was developed, refining the investment strategy both in the area of sector focus and timing of the savings. The recent first 18 months of experience in operating current programs, combined with the experience in the previous programs, also contributed to the plan, which details the investment strategy from 2001/02 to 2011/12.

The savings targets/forecast in the 10-year plan are somewhat lower than the achievable forecast from the CPR. This is due to the desire to balance investment dollars and timing, along with the fact that the resultant program level plans add more knowledge to the estimates from the CPR process. The 10-Year target for Power Smart is to save 3,618 GWh per year by the year 2011/12. The 2003 Electric Load Forecast starts with year-end billing data for

2002/03, which includes the results of all Power Smart investments prior to that date. As a result, Power Smart savings estimate seen in this and any future load forecast will show future effects less than the 10-year target as more and more of the effects are built into the forecast starting point.

The plan also addresses some fuel switching initiatives that are cost-effective. Vancouver Island has an increasing peak capacity issue, which is exacerbated by the fact that a high proportion of residential customers are choosing electric space heating, even when natural gas is available. A number of small fuel-switching initiatives are being examined and are included in the plan. A complete inventory of the fuel-switching potential is not available, but some preliminary estimates are included as a component of the plan. Fuel switching initiatives will be broken out by application, type of fuel and efficiency of conversion, and will identify the net impact on greenhouse gas emissions, but they only represent about five per cent of the total Power Smart portfolio.

Load displacement initiatives are considered "Clean" (as defined in the B.C. Energy Plan) as they are expected to use biomass fuel. Fuel switching initiatives included in the plan meet all appropriate cost effectiveness tests and take into account the full life-cycle electric and gas costs.

12.2.2. Base Case Savings

This 10-year plan has been developed by drawing on the market intelligence contained in the CPR, plus other opportunities that were outside of the scope of the CPR. The 10-year plan's base case energy savings target (at the customers' meter, net of free riders, free drivers, and measurement and verification allowances) is 3,618 GWh per year by 2011/12, and requires an investment of $690.6 million. This yields a cost-effective levelized utility cost and a total resource cost of $0.021/kWh and $0.044/kWh respectively. The customer bill savings resulting from the electricity savings identified in this plan is calculated at $2.28 billion at current electricity rates.

Approximately 59 per cent of the 10-year energy savings target comes from the industrial sector, compared to 21 per cent from government and other commercial, and 20 per cent from residential.

Several factors outside of BC Hydro's control could have an impact on the actual energy savings that are achieved. For example, with 59 per cent of the total 10-year energy savings coming from the industrial sector, the plan is very dependent on stability in that sector.

Issues such as softwood lumber tariffs or the general health of the economy could have significant impacts on the industrial sector's participation, and hence on the overall 10-year target. Further, a heavy dependence on market transformation in terms of its percentage of the 10-year target would make the plan more risky. Finally, overall market penetration assumptions surrounding direct energy acquisition are by no means certain.

12.2.3. Mitigation of Risks

Because there are risks in preparing this plan, a number of steps have been taken to mitigate these risks and lessen their impacts. First, the plan has been assembled to minimize dependence on market transformation. Only seven per cent of the 3,618 GWh per year target is related to market transformation.

Second, in order to reflect the risks and uncertainties characteristic of the base case target, a range has been developed within which the actual 10-year energy

savings are expected to result. The upper end of the range is approximately 4,225 GWh per year (at an investment of $739.5 million) whereas the lower end is approximately 3,011 GWh per year (at an investment of $618.6 million). Importantly, the plan passes all cost-effectiveness tests under both the low and high scenarios.

Third, it is important to emphasize that the upper and lower ends of the range do not represent a "best case" / "worst case" view. Given that the market penetration assumptions characteristic of this range are largely linked to the "most likely" achievable potential scenario from the Conservation Potential Review, there is additional upside potential which could generate a "best case" that is higher than the upper scenario. Conversely, should major events transpire during the planning period which adversely affect consumer confidence or the overall economy, thus triggering a major recession, then the true "worst case" could be significantly worse than the lower scenario.

12.2.4. 10-Year Plan Allocation

In order to achieve the base case energy savings target of 3,618 GWh per year, a 10-year portfolio investment of $690.6 million is required, and allocated as follows:

- 39 per cent, or $265.6 million, is invested in the industrial sector to capture load displacement and various demand-side managment opportunities, largely through the Power Smart Partners program.
- 25 per cent, or $171.9 million, is invested in the government and other commercial sectors in pursuit of opportunities related to lighting and other end uses through existing and new programs such as Power Smart Partners, SUCH, Power Smart Express and New Construction.
- 16 per cent, or $112.4 million, is invested in the residential sector, in pursuit of opportunities related to lighting, appliances and home envelope through new and existing programs such as compact fluorescent lighting (CFL), Refrigerator Buy-back, Home Energy Upgrade, Power Smart New Home and various fuel switching initiatives.
- Eight per cent, or $52.4 million, is invested in public education and non-program specific communications with customers
- 12 per cent, or approximately $88.3 million, is invested in various enabling costs, overheads, administration and management.

13 Glossary

Coincidence Factor A ratio reflecting the relative magnitude of a region's (or customer's or group of customers') demand at the time of the system's maximum peak demand to the region's (or customer's or group of customers') maximum peak demand.

Consumer Price Index (CPI) An inflation index calculated by comparing the price of a typical bundle of goods in the year in question to the price of the same goods in a set reference year.

Demand-Side Management (DSM) The influencing of energy demand to achieve socially economic efficiency improvements in the end use of electricity, and to shift electricity demand to reduce utility capacity costs.

Region A geographical sub-division of the BC Hydro service area. Four regions exist: Lower Mainland, Vancouver Island, South Interior and the Northern Region.

Distribution voltage customer A BC Hydro customer who receives electricity via distribution lines that operate at relatively low voltage (34 kV and less).

Diversity That quality or characteristic by which individual maximum demands occur at different times. Diversity may be examined on an hourly, daily, monthly or yearly basis.

Econometric modelling The use of statistical techniques, typically regression analysis of time-series and/or cross-sectional data, to detect statistically verifiable relationships, coherent with economic theory, between an explained variable (e.g. electricity consumption) and explanatory variables (e.g. industry output, prices of alternative energy inputs and GDP).

Elasticity The proportionate change in a dependent variable, (e.g. electricity consumption, divided by the proportionate change in a specified independent variable; electricity price). A dependent variable is highly elastic with respect to a given independent variable if the calculated elasticity is much greater than one. The dependent variable is inelastic if the elasticity is less than one.

End-use model A model used to analyze and forecast energy demand, which focuses on the end uses or services provided by energy. Typical end uses are lighting, process heat and motor drive. For a given industry, the model estimates the influence of prices and technological change on the evolution of the secondary energy inputs required to satisfy the industry's end uses over time.

Energy The amount of electricity delivered or consumed over a certain time period, measured in multiples of watt-hours. A 100-watt bulb consumes 200 watt-hours in two hours. A typical BC Hydro residential account consumes about 10,000 kWh (10 million watt-hours) annually.

Intensity A unitized measure of energy consumption, typically in kilowatt-hours per unit of stock. For example, kWh per account in the residential sector or kWh per unit of production in the industrial sector.

Gross Domestic Product (GDP) A measure of the total flow of goods and services produced by the economy over a specified time period, normally a year or quarter. It is obtained by valuing outputs of goods and services at market prices (alternatively at factor cost), and then aggregating the total of all goods and services.

Gigawatt-hour (GWh) A measure of electrical energy, equivalent to one million kilowatt-hours. (See Units of Measure.)

Integrated system That portion of the BC Hydro system which is connected as one whole. Non-integrated facilities refer to generating facilities that are not connected to the system, located in remote areas of the province.

kilowatt-hour (kWh) A measure of electrical energy, equivalent to the energy consumed by a 100-watt bulb in 10 hours. (See Units of Measure.)

Load The total amount of electrical power demanded by the utility's customers at any given time, typically measured in megawatts (MW).

Megawatt (MW) A unit used to measure the capacity or potential to generate or consume electricity. One MW equals one million watts. (See Units of Measure.)

Monte Carlo method A technique for estimating probabilities involving the construction of a model and the simulation of the outcome of an activity a large number of times. Random sampling techniques are used to generate a range of outcomes. Probabilities are estimated from an analysis of this range of outcomes.

MVA Megavolt-Amps – a unit of apparent power. Apparent power is real power in MW divided by power factor.

Natural conservation The increase in energy efficiency that would occur in the absence of any utility-induced demand-side management program, all other things being equal.

Normalization The correction of actual customer sales and peak demand for factors such as unusually warm or cold weather.

Price elasticity of demand The percentage change in quantity demanded, divided by the percentage change in price that caused the change in quantity demanded.

Real price increases that have been adjusted for changes in prices of all goods. The nominal price of an item may rise by 10 per cent over a year, but inflation (and assumed wages) may have risen by seven per cent over the same time period. Therefore the effective price increase faced by the consumer is three per cent. It is necessary to deflate current prices by an appropriate inflation index (the CPI in Canada) to convert money values to constant prices or real terms.

Stock A quantity representing a number of energy consuming units. For example, in the residential sector, stock is the number of accounts or housing units; in the commercial sector, stock is represented by the floor area of commercial building space.

System peak demand The greatest combined demand of all BC Hydro customers faced by the generation system during a given fiscal year.

Transmission voltage customer A BC Hydro customer that is supplied its electricity via high-voltage transmission lines (60 kV or above).

Units of measure The large amounts of electricity generated and consumed on a system-wide basis are discussed in multiples of the basic units of watt and watt-hours. Kilowatts and megawatts are used to measure power, and kilowatt-hours, megawatt-hours, and gigawatt-hours are used to measure energy. The equivalence are:

1 kilowatt (kW)	=	1000 watts
1 megawatt (MW)	=	1000 kilowatts or 1 million watts
1 kilowatt-hour (kWh)	=	1000 watt-hours
1 megawatt-hour (MWh)	=	1000 kilowatt-hours or 1 million watt-hours
1 gigawatt-hour (GWh)	=	1000 megawatt-hours or 1 billion watt-hours

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Appendix 1. Price and Income Elasticities For Electricity Consumption

The own price elasticity of electricity consumption is a measure of the responsiveness of the quantity of electricity demanded to a small change in electricity price. Formally, the definition of the own price elasticity of consumption is shown in (A1.1).

(A1.1) $\varepsilon = (\Delta C/C)/(\Delta P/P)$

Here:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- P refers to an electricity price index.

The own price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in electricity price.

The cross price elasticity of electricity consumption is a measure of the responsiveness of the quantity of electricity demanded to a small change in gas price. Formally, the definition of the cross price elasticity of consumption is shown in (A1.2).

(A1.2) $\varepsilon = (\Delta C/C)/(\Delta G/G)$

Here:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- G refers to a gas price index.

The cross price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in gas price.

The income elasticity of electricity consumption is a measure of the responsiveness of the quantity of electricity demanded to a small change in income. Formally, the definition of the income elasticity of consumption is shown in (A1.3).

(A1.3) $\eta = (\Delta C/C)/(\Delta Y/Y)$

Here:

- Δ refers to a small change in the following variable;
- C refers to consumption in GWh; and
- Y refers to a provincial GDP in billions of constant 1997 dollars.

The income elasticity of consumption measures the percentage change in consumption caused by a one per cent change in income.

Maximum likelihood methods are used to estimate the price and income elasticities of electricity consumption for the total domestic load. The outcome variable is the log of the total domestic load in GWh (on a weather-adjusted basis). The independent variables are the log of real GDP in billions of 1997 dollars, the log of the price of electricity to a base of 1997 = 100, and the log of the real price of natural gas to a base of 1997 = 100.

The Cobb-Douglas specifications are used, and the model is estimated both with (A1.4) and without (A1.5) gas prices as an explanatory variable, where e is the error term.

(A1.4) $\ln C_t = \text{Inconstant} + \alpha * \ln Y_t + \beta * \ln P_t + e_t$

(A1.5) $\ln C_t = \text{Inconstant} + \alpha * \ln Y_t + \beta * \ln P_t + \gamma * \ln G_t + e_t$

In both cases, the error terms are modeled as first-order auto-regressive scheme (A1.6)

(A1.6) $e_t = \rho e_{t-1} + u_t,\ t = 1, 2, \ldots, T$

Assuming that the absolute value of the parameter ρ is less than one, the u_t are independently and identically distributed with variance σ_u^2, and e_t are generated by a stationary stochastic process beginning in the indefinite past. Roughly speaking, a stochastic process is stationary if the mean, variance and covariance's for given lags are constant.

Table A1.1 shows that according to Model 1, the "without gas" price model, a one per cent increase in GDP increases domestic electricity sales by 0.42 per cent while a one per cent increase in the price of electricity reduces domestic electricity sales by 0.30 per cent. According to Model 2, the "with gas" price model, a one per cent increase in GDP increases domestic electricity sales by 0.28 per cent, a one per cent increase in the price of electricity sales reduces electricity sales by 0.60 per cent, and a one per cent increase in price of gas reduces electricity demand by 0.034 per cent. The negative sign for the effect of gas prices is counter-intuitive. Given this anomaly in the impact of natural gas price, the "without gas" price estimates are more appropriate for the analysis of energy consumption sensitivities.

Table A1.1. Maximum Likelihood Estimates of Energy Elasticities

Variable	Model 1 (Without Gas)	Model 2 (With Gas)
Constant	7.21 (3.63)	10.3 (4.33)
Log GDP	0.42 (0.20)	0.28 (0.23)
Log electricity price	-0.30 (0.28)	-0.60 (0.37)
Log gas price	-	-0.034 (0.028)
Log likelihood	30.8	31.8
Durbin-Watson	2.24	2.14

Appendix 2. Price and Income Elasticities For Peak Demand

The own price elasticity of electricity peak demand is a measure of the responsiveness of peak demand to a small change in price. Formally, the definition of the own price elasticity of peak demand is shown in (A2.1).

(A2.1) $\varepsilon = (\Delta D/D)/(\Delta P/P)$

As before:

- Δ refers to a small change in the following variable;
- D refers to peak demand in MW; and
- P refers to an electricity price index.

The own price elasticity of peak demand measures the percentage change in peak demand caused by a one per cent change in electricity price.

The cross price elasticity of electricity consumption is a measure of the responsiveness of peak demand to a small change in gas price. Formally, the definition of the cross price elasticity of consumption is shown in (A2.2).

(A2.2) $\varepsilon = (\Delta D/D)/(\Delta G/G)$

Here:

- Δ refers to a small change in the following variable;
- D refers to demand MW; and
- G refers to a gas price index.

The cross price elasticity of consumption measures the percentage change in consumption caused by a one per cent change in gas price.

The income elasticity of electricity peak demand is a measure of the responsiveness of peak demand to a small change in income. Formally, the definition of the income elasticity of peak demand is shown in (A2.3).

(A2.3) $\eta = (\Delta D/D)/(\Delta Y/Y)$

Here:

- Δ refers to a small change in the following variable,
- D refers to peak demand in MW; and
- Y refers to a provincial GDP in billions of constant 1997 dollars.

The income elasticity of peak demand measures the percentage change in peak demand consumption caused by a one per cent change in income.

Maximum likelihood methods are used to estimate the price and income elasticities of peak demand for the total domestic load. The outcome variable is the log of the total peak load in MW (on a weather-adjusted basis), and the independent variables are the log of real GDP in billions of 1997 dollars, the log

of the price of electricity to a base of 1997 = 100, and the log of the real price of natural gas to a base of 1997 = 100.

The Cobb-Douglas specifications are used and the model is estimated both with (A2.4) and without (A2.5) gas prices as an explanatory variable, where e is the error term.

(A2.4) $\ln C_t = \text{Inconstant} + \alpha * \ln Y_t + \beta * \ln P_t + e_t$

(A2.5) $\ln C_t = \text{Inconstant} + \alpha * \ln Y_t + \beta * \ln P_t + \gamma * \ln G_t + e_t$

In both cases the error terms are modelled as first-order auto-regressive scheme (A2.6)

(A2.6) $e_t = \rho e_{t-1} + u_t, t = 1, 2, \ldots, T$

Assuming that the absolute value of the parameter ρ is less than one, the u_t are independently and identically distributed with variance σ_u^2, and e_t are generated by a stationary stochastic process beginning in the indefinite past. Roughly speaking, a stochastic process is stationary if the mean, variance and covariance for given lags are constant.

Table A2.1 shows that according to Model 1, the "without gas" price model, a one per cent increase in GDP increases domestic peak demand by 0.25 per cent while a one per cent increase in the price of electricity reduces domestic peak demand by 0.32 per cent. According to Model 2, the "with gas" price model, a one per cent increase in GDP increases domestic electricity sales by 0.24 per cent, a one per cent increase in the price of electricity sales reduces electricity sales by 0.36 per cent, and a one per cent increase in price of gas reduces electricity demand by 0.0085 per cent. Again, the negative sign for the effect of gas prices is counter-intuitive. Given this anomaly in the impact of natural gas price, the "without gas" price estimates are more appropriate for the analysis of peak demand sensitivities.

Table A2.1. Maximum Likelihood Estimates of Peak Elasticities

Variable	Model 1 (Without Gas)	Model 2 (With Gas)
Constant	7.63 (4.41)	8.00 (4.93)
Log GDP	0.25 (0.25)	0.24 (0.27)
Log electricity price	-0.32 (0.35)	-0.36 (0.41)
Log gas price	-	-0.0085 (0.031)
Log likelihood	29.9	30.0
Durbin-Watson	1.62	1.65

Appendix 3. Weather Normalization for Energy

Weather-normalized sales are an estimate of the sales that would have been made if normal weather had been experienced. Sales are adjusted using heating degree-days (a standard approach used by the utility industry). A degree-day is measure of coldness, defined by the number of degrees below 18 degrees Celsius in (A3.1), for the average daily temperature. For example, if the average temperature on day t is 12 degrees Celsius then that day has 18-12 = 6 heating degree-days. The heating degree-days for a month are the sum of the heating degree-days for the days in that month.

Formally, for day t heating degree-days is defined in (A3.1) where max is the maximum function.

(A3.1) heating degree-day$_t$ = max (18°C – average daily temperature, zero)

Note that degree-days are never negative because the heating system will not be required to produce heat at temperatures above 18°C.

We assume that the monthly residential use rate for a given class of residential accounts can be modelled using the following cubic polynomial (A3.2.).

(A3.2) use rate$_t$ = $\alpha + \beta^*HDD_t + \chi^*HDD_t^2 + \delta^*HDD_t^3 + \varepsilon_t$

The most recent 36 months of data available is used to estimate each regression, which is modelled using ordinary least squares. To calculate the weather-adjusted use rate for a particular period, the heating degree-days for the period are substituted into the estimated regression equation (A3.2).

It is important to note the following points:

- First, weather normalization is undertaken for the residential sector only since only limited evidence exists of weather response for the commercial and industrial sectors. This means that when weather-normalized totals are reported, only the residential part of the total is actually weather-adjusted. Although this is not viewed as a major source of error, research is being conducted to determine if and how the commercial and industrial loads should be weather normalized.
- Second, the model actually normalizes the use per account or the use rate rather than sales per se. Normalized sales are then calculated as normalized use rate multiplied by the average number of accounts for the class. Eight classes are used in these calculations, namely a heating and non-heating class in each of the four regions.
- Third, because this forecast uses billed sales rather than the unknown actual consumption by class, monthly heating degree-days are allocated using a 25/50/25 per cent adjustment to match the assumed pattern of meter reading.

Table A3.1 compares the actual and weather-normalized sales for BC Hydro's service territory for the fiscal years 1993/94 to 2002/03.

Table A3.1. Actual and Weather-Normalized Sales for BC Hydro Service Territory

Year	Actual (GWh)	Weather Normalized (GWh)
1993/94	40,979	41,367
1994/95	41,616	41,992
1995/96	42,851	43,055
1996/97	43,598	43,095
1997/98	42,607	43,115
1998/99	44,863	45,418
1999/00	45,638	45,542
2000/01	46,806	46,628
2001/02	46,412	46,252
2002/03	47,612	47,789
2003/04	48,774	48,776

Appendix 4. Weather Normalization for Peak

The domestic generation load is made up of the transmission load plus the distribution load plus losses. The transmission load is assumed to be insensitive to weather. The distribution load is sensitive to weather primarily through the residential heating load. Using appropriate data, the transmission load is netted out and the distribution load then weather normalized separately.

A daily peak model was estimated for each year to be weather normalized. Daily peaks are modelled as a function of trend, day type, and weather variables. The daily peak model is specified as (A4.1).

$$(A4.1)\quad peak_t = \alpha + \beta * trend_t + \chi * weekend_t + \delta * xmas_t + \phi * daylight_t + \gamma * temp_t + \eta * temp_t * daylight_t + \varphi * temp_t^2 + \lambda * temp_t^3 + \varepsilon_t$$

The variables are as follows.

- Peak is the daily peak in MW;
- Trend is a linear trend indexed by day t of the year;
- Weekend takes the value one for weekends and holidays and zero for weekdays;
- Xmas takes the value one for days between Christmas and New Year and zero otherwise;
- Daylight is the number of daylight hours;
- Temp is the daily average temperature; and
- ε is the random error.

Once the model is estimated, the estimated daily peak model for each given year is loaded with the preceding 30 historical weather years (a set of 365 daily temperatures), one year at a time. The simulated annual peaks are found for each of the 30 annual simulations. A histogram can be generated, showing the probability distribution of the annual simulated peaks. The weather-normalized peak for each given year is computed as the average of the thirty simulated annual peaks.

Table A4.1 compares the actual and weather-normalized sales for BC Hydro's service territory for the fiscal years 1993/94 to 2002/03. Note that elsewhere the peak is for the integrated system and is somewhat higher.

Table A4.1. Actual and Weather-Normalized Peak for BC Hydro Integrated System

Year	Actual (MW)	Bottom-up Approach Substation Weather-Normalized[1] (MW)	Top-Down Procedure Weather-Normalized (MW)	Weather-Adjusted Base Year for Forecast
1994/95	8,168	8,253	-	8,253
1995/96	8,451	8,301	-	8,301
1996/97	8,267	8,271	-	8,271
1997/98	8,243	8,385	-	8,385
1998/99	8,777	8,772	9,076	8,772
1999/00	8,423	8,835	9,053	8,835
2000/01	8,995	8,986	9,154	8,986
2001/02	8,692	9,016	9,339	9,016
2002/03	8,481	8,972	9,127	9,082
2003/04	9,619	9,382	9,450	9,431

Appendix 5. Ordinary Least Squares-Based Forecasts

Most economic analysis deals with situations where the outcome variables can be assumed to be continuous and normally distributed. These include decisions about how much of a product to purchase, how much of a product to produce and what price to charge for a product. In each of these cases, explaining the determinants of the variable typically involves modelling the outcome variable as a continuous function of a set of k explanatory or independent variables, a set of k associated parameters, plus an error term ε assumed to be normally distributed with mean zero, constant variance σ^2 and covariance's equal to zero (there is no correlation between errors for different observations). The basic idea of least squares regression is to choose the parameters to minimize the sum of squares of the errors. The assumption of normally distributed errors is not necessary to apply ordinary least squares regression, but some assumption on the distribution of errors is needed to generate test statistics for the parameters.

The rationale for using minimum least squared error as the criterion for choosing parameter values makes intuitive sense since large errors are more important than are small errors. Equally important is the fact that ordinary least squares estimators have desirable properties in the classical regression context. In particular, ordinary least squares estimates are unbiased and have minimum variance in the class of linear unbiased estimators. In other words, they are the best estimator for this class of regression problem.

In the typical set-up, then, the regression model is given by:

(A5.1) $y_t = x'_t\beta + \varepsilon_t$, where $\varepsilon_t \sim N(0, \sigma^2)$ and t = 1,2, ... T

Here:

- y_t is the dependent variable at observation;
- t is a k×1 vector of independent variables at observation t;
- β is a k×1 vector of parameters assumed constant for all observations; and
- T is the number of observations.

In other words, (A5.1) is a set of T equations where the value of y_t at time t is a linear function of k variables, $x_{1t}, x_{2t}, \ldots, x_{kt}$.

It is convenient for what follows to write equation (A5.1) in matrix form as follows

(A5.2) $y = X'\beta + \varepsilon$,

where:

- y is a T×1 vector;
- X is a k×T matrix;
- β is a T×1 vector; and
- ε is a T×1 vector.

Assuming that X is a non-stochastic matrix of full rank $k \leq T$ that satisfies the regularity condition $\lim_{T \to \infty} (X'X/T) = Q$, where Q is a finite and non-singular matrix, and using E for the expectation operator, note that the $E(\varepsilon)$ is zero since the expectation of each of its components is zero.

Defining the sum of the squared errors as S, note that the variance of the errors is the expectation of S:

(A5.3) $S \equiv \varepsilon'\varepsilon = (y - X'\beta)' (y - X'\beta)$ and $E\varepsilon\varepsilon' = \sigma^2 I$

The ordinary least squares estimators of the vector of parameters β^* and the variance of the errors σ^{2*} are found by minimizing the sum of the squared errors

(A5.4) $\partial S/\partial\beta = -2X'y + 2X'X\beta^* = 0$

Solving (A6.5) for β^* the estimated value of β yields the following expression

(A5.5) $\beta^* = (X' X)^{-1} X' y$

The ordinary least squares estimate of the variance of the errors σ^2 is given by the following expression:

(A5.6) $\sigma^{2*} = \varepsilon^{*\prime}\varepsilon^* / (T - k)$ where $\varepsilon^* = y - X\beta^*$

The estimate of σ^2 is used to estimate confidence intervals and to conduct hypotheses tests for the parameters. Further, the least squares estimates of the parameters can be shown to be unbiased and consistent estimates of the population parameters.

It may be useful to find the effect of a change in an independent variable on the outcome variable. This partial effect is found by calculating the relevant partial derivative and in the linear model is just the value of the regression coefficient for that variable.

(A5.7) $\partial y/\partial x = \partial(X\beta + \varepsilon)\partial x = \beta$, since the derivative of ε is zero.

Finally, the measure of goodness of fit for an ordinary least squares regression is R-squared adjusted for degrees of freedom, which is calculated as the explained sum of square divided by the total sum of squares times T – k divided by T.

Table A5.1 presents ordinary least squares regression models for energy by sector, total sales, gross requirements and peak based on weather normalised data for 1994/95 to 2003/04. The dummy variable takes on the value 1 for 1997/98 and 2001/02 and zero otherwise and is designed to capture the effects of strike activity.

The models do not account for the impacts of price changes or the anticipated phase out of Highland Valley Cooper.

Table A5.1. Ordinary Least Squares Regressions

	Residen-tial (GWh)	Commer-cial (GWh)	Indust-rial (GWh)	Total Firm Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated Sys. Peak* (MW)
Actual (not weather-normalized)						
Constant	3,588 (1,724)	840 (413)	9,993 (1,263)	11,352 (1,858)	16,290 (2115)	2.748 (545)
GDP	0.091 (0.015)	0.10 (0.0035)	0.068 (0.011)	0.30 (0.016)	0.30 (0.018)	0.052 (0.0046)
Dummy	-	-	-1,082 (212)	-1,106 (311)	-1277 (354)	-136 (91)
Adjusted R-squared	0.81	0.99	0.87	0.96	0.97	0.93
Durbin-Watson	1.42	1.18	2.38	2.31	3.20	2.31

Table A5.2 presents forecasts for energy by sector, total sales, gross requirements and peak based on weather normalised data for 1994/95 to 2003/04. The dummy variable takes on the value 1 for 1997/98 and 2001/02 and zero otherwise and is designed to capture the effects of strike activity.

The models do not account for the impacts of price changes or the anticipated phase out of Highland Valley Cooper.

Table A5.2. Ordinary Least Squares Forecasts Before Power Smart

	Residen-tial (GWh)	Commer-cial (GWh)	Indust-rial (GWh)	Total Firm Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrated Sys. Peak* (MW)
Actual (weather-normalized)						
1994/95	13,292	11,611	17,087	43,029	47,610	8,253
1995/96	13,504	11,920	17,630	43,795	48,389	8,301
1996/97	13,480	12,226	17,549	44,019	49,292	8,271
1997/98	14,310	12,465	16,338	43,890	48,480	8,385
1998/99	14,527	12,814	18,077	46,360	51,519	8,772
1999/00	14,477	13,176	17,890	46,596	51,428	8,835
2000/01	14,395	13,654	18,579	48,026	52,840	8,986
2001/02	14,930	13,583	17,739	47,627	52,330	9,016
2002/03	15,464	13,729	18,596	49,176	53,563	9,082
2003/04	15,901	14,151	18,724	50,275	55,186	9,564
Forecast (Residential energy and System Peak forecasts assume "normal weather")						
2004/05	15,897	14,641	19,173	51,464	56,266	9,624
2005/06	16,279	15,068	19,458	52,708	57,505	9,838
2006/07	16,672	15,509	19,751	53,990	58,783	10,057
2007/08	17,065	15,949	20,004	55,269	60,057	10,277
2008/09	17,456	16,388	20,336	56,452	61,327	10,495
2009/10	17,844	16,823	20,625	57,808	62,588	10,712
2010/11	18,300	17,334	20,965	59,294	64,069	10,967
2011/12	18,653	17,730	21,229	60,445	65,216	11,164
2012/13	19,015	18,136	21,498	61,623	66,390	11,366
2013/14	19,385	18,551	21,775	62,830	67,593	11,573
2014/15	19,780	18,994	22,069	64,117	68,875	11,794
2015/16	20,185	19,447	22,371	65,436	70,190	12,020
2016/17	20,583	19,894	22,668	66,734	71,484	12,242
2017/18	20,991	20,351	22,972	68,063	72,808	12,470
2018/19	21,409	20,819	23,284	69,242	74,165	12,703
2019/20	21,836	21,299	23,603	70,818	75,554	12,942
2020/21	22,256	21,770	23,916	72,185	76,917	13,177
2021/22	22,685	22,251	24,236	73,585	78,311	13,417
2022/23	23,125	22,743	24,563	75,016	79,737	13,662
2023/24	23,574	23,247	24,899	76,480	81,197	13,913
2024/25	24,034	23,762	25,241	77,978	82,690	14,170
Growth Rates						
5 years: 98/99 - 03/04	1.8%	2.0%	0.7%	1.6%	1.4%	1.7%
5 years: 03/04 - 08/09	1.9%	3.0%	1.7%	2.3%	2.1%	1.9%
10 years: 03/04 - 13/14	2.0%	2.7%	1.5%	2.3%	2.0%	1.9%
Last 11 years: 13/14 - 24/25	2.0%	2.3%	1.4%	2.0%	1.8%	1.9%

Appendix 6. Maximum Likelihood-Based-Based Forecasts

The main alternative to least squares estimation is maximum likelihood estimation. It is normally used in circumstances where the underlying assumptions of the standard linear model are not met, but it is convenient to first review maximum likelihood estimation of the standard linear model (described in Appendix 5) before considering the more complicated case of auto-correlated residuals. The basic idea of maximum likelihood estimation is to choose estimates for the parameter values that maximize the probability that the distribution represented by the estimated parameters generated the observed sample.

Formally, consider the normal linear regression model considered in Appendix 5, the joint likelihood for the T observations is the product of T normal densities as follows:

(A6.1) $L = f(y_1, y_2, \ldots, y_T) = (2\pi\sigma^2)^{-T/2} \exp\{-(2\sigma^2)^{-1}(y - X\beta)'(y - X\beta)\}$

Taking the log of this expression yields:

(A6.2) $\ln L = -T/2 \ln(2\pi) - T/2 \ln(\sigma^2) - (2\sigma^2)^{-1}(y - X\beta)'(y - X\beta)$

Maximizing the log likelihood function with respect to the parameters yields the first order conditions given by expressions (A6.3) and (A6.4):

(A6.3) $\partial L/\partial\beta = -\sigma^{-2}(-X'y + X'X\beta) = 0$

(A6.4) $\partial L/\partial\sigma^2 = -T(2\sigma^2)^{-1} + (2\sigma^4)^{-1}(y - X\beta)'(y - X\beta) = 0$

Solving these equations for the unknown parameters yields the estimators (A6.5) and (A 6.6):

(A6.5) $\beta^{**} = (X'X)^{-1}X'y$

(A6.6) $\sigma^{2**} = \varepsilon^{**}{}'\varepsilon^{**}/T = (T - k)/T\,\sigma^{2*}$

The maximum likelihood estimate of β is the same as the ordinary least squares estimate for this model and is unbiased and consistent. The maximum likelihood estimate of σ^2 is different from the ordinary least squares estimate by the factor $T/(t - k)$, and is therefore a biased estimator, but it is a consistent estimate since as $T \to \infty$ the bias goes to zero. In fact, the strength of maximum likelihood estimators is that under fairly general conditions they are consistent, asymptotically normal and asymptotically efficient. These features account for their widespread use in econometrics in situations where least squares estimates are inappropriate because the requirements of the classical linear regression model are not met.

Up to now we have assumed that covariance's of the errors are zero or that there is no auto-correlation. However in many cases, errors are correlated over time, often due to persistent shocks reflecting the inertia of economic processes or due to omitted variables that are hopefully uncorrelated to variables in the model.

Consider the linear model:

(A6.7) $y = X'\beta + \varepsilon,$

where:

- y is a T×1 vector;
- X is a k×T matrix;
- β is a T×1 vector; and
- ε is a T×1 vector;

but where:

(A6.8) $\varepsilon_t = \rho\varepsilon_{t-1} + u_t, t = 1,2, \ldots,T$

Assuming that the absolute value of the parameter ρ is less than one, the u_t are independently and identically distributed with variance σ_u^2, and ε_t are generated by a stationary stochastic process beginning in the infinite past. Roughly speaking, a stochastic process is stationary if the mean, variance and covariance's for given lags are constant over time.

The form of the errors is awkward to work with and the calculations can be simplified by expanding the previous expression by making successive substitutions for ε_t to yield:

(A6.9) $\varepsilon_t = \Sigma\rho^i u_{t-i}$, where the sum runs over $i = 0,1,\ldots,\infty$

Using the assumptions on u_t and the formula for the sum of a converging series gives the variance of ε_t as follows:

(A6.10) $E(\varepsilon_t^2) = \rho^0 E(u_t^2) + \rho^2(u_t^2) + \rho^4 E(u_u^4) + \ldots = \sigma_u^2/(1 - \rho^2) = \sigma_\varepsilon^2$

Finally, the covariance of ε_t with ε_{t-i} is needed, which is:

(A6.11) $E(\varepsilon_t\varepsilon_{t-i}) = E([u_t + \rho u_{t-1} + \rho^2 u_{t-2} + \ldots]*[u_t + \rho u_{t-1} + \rho^2 u_{t-2} + \ldots]) = \rho^i\sigma_\varepsilon^2$

This gives all the variances and covariance's in the variance-covariance matrix for ε_t. Noting that every term contains σ_u^2, this common term can be extracted and the variance-covariance matrix can be written as follows:

(A6.12) $E\varepsilon\varepsilon' = \sigma_u^2\Omega$

If the value of ρ were known, the value of β could be found that minimizes this sum of squares as with for the ordinary least squares estimator to yield the generalized least squares estimator:

(A6.13) $\beta^* = (X'\Omega^{-1}X)^{-1}X'\Omega^{-1}y$

But since the value of ρ is not known, a maximum likelihood estimator can be used, which gives us consistent and asymptotically efficient estimates of the parameters. Starting by formulating the likelihood function in the usual way and taking its log that yields:

(A6.14) $\ln L(y, X, \beta, \sigma_u^2, \rho) = -T/2 \ln(2\pi) - 1/2 \ln|\sigma_u^2\Omega| - (2\sigma_u^2)^{-1}(y - X\beta)'$
$\Omega^{-1}(y - X\beta)$

This expression can be simplified by partially maximizing with respect to $\beta(\rho)$ and $\sigma_u^2(\rho)$ which, noting that these expressions are functions of ρ, yields the simpler concentrated likelihood function:

(A6.15) $\ln L^*(\rho, y, X) = -T/2\{\ln(2\pi) + 1\} - T/2 \ln\{[\sigma_u^2(\rho)][(1 - \rho^2)^{-1/T}]\}$

Maximizing this function with respect to ρ is then a relatively straightforward numerical estimation problem. The method of Beach-MacKinnon (1978) can be used to maximize this function.

Table A6.1 presents maximum likelihood regression models for energy by sector, total sales, gross requirements and peak based on weather normalised data for 1994/95 to 2003/04. The dummy variable takes on the value 1 for 1997/98 and 2001/02 and zero otherwise and is designed to capture the effects of strike activity.

The models do not account for the impacts of price changes or the anticipated phase out of Highland Valley Cooper.

Table A6.1. Maximum Likelihood Regressions

	Residential (GWh)	Commercial (GWh)	Industrial (GWh)	Total Firm Sales (GWh)	Total Gross Requirements (GWh)	Total Integrated Sys. Peak (MW)
Actual (not weather-normalized)						
Constant	3440 (2057)	953 (529)	9897 (1033)	11092 (1629)	16176 (1206)	2725 (361)
GDP	0.093 (0.017)	0.10 (0.0045)	0.069 (0.0089)	0.30 (0.014)	0.30 (0.010)	0.051 (0.0031)
Dummy	-	-	-1048 (213)	-1111 (318)	-1163 (283)	-197 (84)
Log likelihood	-71.8	-57.3	-67.9	-72.0	-71.3	-58.9
Durbin-Watson	1.63	1.82	2.17	2.32	3.25	2.63

Table A6.2 presents forecasts for energy by sector, total sales, gross requirements and peak based on weather normalised data for 1994/95 to 2003/04. The dummy variable takes on the value 1 for 1997/98 and 2001/02 and zero otherwise and is designed to capture the effects of strike activity.

The models do not account for the impacts of price changes or the anticipated phase out of Highland Valley Cooper.

Table A6.2. Maximum Likelihood Forecasts Before Power Smart

	Residen-tial (GWh)	Commer-cial (GWh)	Industrial (GWh)	Total Firm Sales (GWh)	Total Gross Require-ments (GWh)	Total Integrate d Sys. Peak* (MW)
Actual (weather-normalized)						
1994/95	13,292	11,611	17,087	43,029	47,610	8,253
1995/96	13,504	11,920	17,630	43,795	48,389	8,301
1996/97	13,480	12,226	17,549	44,019	49,292	8,271
1997/98	14,310	12,465	16,338	43,890	48,480	8,385
1998/99	14,527	12,814	18,077	46,360	51,519	8,772
1999/00	14,477	13,176	17,890	46,596	51,428	8,835
2000/01	14,395	13,654	18,579	48,026	52,840	8,986
2001/02	14,930	13,583	17,739	47,627	52,330	9,016
2002/03	15,464	13,729	18,596	49,176	53,563	9,082
2003/04	15,901	14,151	18,724	50,275	55,186	9,564
Forecast (Residential energy and System Peak forecasts assume "normal weather")						
2004/05	15,935	14,612	19,187	51,501	56,257	9,633
2005/06	16,322	15,035	19,475	52,753	57,499	9,847
2006/07	16,721	15,472	19,771	54,045	58,780	10,068
2007/08	17,120	15,907	20,068	55,333	60,058	10,288
2008/09	17,516	16,341	20,363	56,616	61,331	10,508
2009/10	17,911	16,772	20,656	57,891	62,595	10,726
2010/11	18,374	17,278	21,000	59,389	64,081	10,982
2011/12	18,732	17,670	21,266	60,548	65,230	11,180
2012/13	19,099	18,071	21,539	61,735	66,408	11,383
2013/14	19,475	18,482	21,819	62,950	67,613	11,590
2014/15	19,876	18,920	22,117	64,247	68,899	11,812
2015/16	20,827	19,369	22,422	65,575	70,217	12,039
2016/17	20,691	19,811	22,723	66,883	71,514	12,263
2017/18	21,105	20,264	23,031	68,222	72,842	12,492
2018/19	21,529	20,727	23,346	69,593	74,202	12,726
2019/20	21,963	21,202	23,669	70,997	75,595	12,966
2020/21	22,389	21,668	23,985	72,375	76,962	13,202
2021/22	22,825	22,144	24,309	73,784	78,360	13,442
2022/23	23,271	22,631	24,641	75,226	79,790	13,689
2023/24	23,727	23,130	24,980	76,702	81,253	13,941
2024/25	24,193	23,640	25,327	78,211	82,750	14,199
Growth Rates						
5 years: 98/99 - 03/04	1.8%	2.0%	0.7%	1.6%	1.4%	1.7%
5 years: 03/04 - 08/09	2.0%	2.9%	1.7%	2.4%	2.1%	1.9%
10 years: 03/04 - 13/14	2.0%	2.7%	1.5%	2.3%	2.1%	1.9%
Last 11 years: 13/14 - 24/25	2.0%	2.3%	1.4%	2.0%	1.9%	1.9%

* Values shown in brackets are based on weather normalized actuals

Appendix 7. Industrial Sector Regressions

Tables A7.1 through A7.4 summarise alternative econometric estimates of the determinants of electricity consumption for the industrial sector and compares them to the reference forecast developed with the above methodology. The regressions are as follows:

- OLS (Transmission). Ordinary least squares regression of transmission industrial sales on GDP and with/without a dummy variable for 1997 and 2001 because of work stoppages (Model 1 and Model 2 respectively). Ordinary least squares regression is a method of choosing parameters to minimise the sum of squares of errors produced as a function of a set of variables (See Appendix 5) ;
- ML (Transmission). Maximum likelihood regression of industrial sales on GDP and with/without a dummy variable for 1997 because of work stoppages (Model 1 and Model 2 respectively). Maximum likelihood regression is a method to choose estimates for parameter values that maximise the probability that estimated parameters will represent an observed sample (See Appendix 6);
- OLS (Distribution). Ordinary least squares regression of distribution industrial sales on GDP and with/without a dummy variable for 2000 because of low economic activity with the recession (Model 1 and Model 2 respectively);
- ML (Distribution). Maximum likelihood regression of distribution industrial sales on GDP and with/without a dummy variable for 2000 (Model 1 and Model 2 respectively).

The OLS industrial transmission sales equation for Model 1 has an adequate fit with an adjusted R-squared values of 0.38, although the Durbin-Watson statistic suggests the possible presence of auto-correlation. (The Durbin-Watson is a measure of auto-correlation, which means that the errors are correlated over time rather than being independent as assumed in the ordinary least squares model. If the errors are auto-correlated, then use of a maximum likelihood estimation procedure may lead to statistically superior estimates.) The ML industrial transmission sales equation looks reasonable with coefficients having the anticipated signs. The Durbin-Watson statistic is better (closer to the desired value of 2.0) suggesting that auto-correlation has been reduced.

Table A7.1. Econometric Model of Industrial Transmission Sales (Model 1)

Variable	OLS	ML
Constant	7024 (2736)	7078 (2183)
GDP	0.0592 (0.0231)	0.0587 (0.0185)
Dummytran	-	-
Adjusted R-sq	0.38	-
Log likelihood	-	-76.2
Durbin-Watson	2.62	2.25
Estimated Auto	-0.31	-0.13

The OLS industrial transmission sales equation for Model 2 has a good fit with an adjusted R-squared values of 0.80, although the Durbin-Watson statistic suggests the possible presence of auto-correlation. (The Durbin-Watson is a measure of auto-correlation, which means that the errors are correlated over time rather than being independent as assumed in the ordinary least squares model. If the errors are auto-correlated, then use of a maximum likelihood estimation procedure may lead to statistically superior estimates.) The ML industrial transmission sales equation looks reasonable with coefficients having the anticipated signs. The Durbin-Watson statistic is better (very close to the desired value of 2.0) suggesting that auto-correlation has been reduced. According to this model, a one billion dollar increase in provincial GDP increases the industrial transmission demand for electricity by 64 MWh.

Table A7.2. Econometric Model of Industrial Transmission Sales (Model 2)

Variable	OLS	ML
Constant	8112 (1737)	8682 (970)
GDP	0.0512 (0.015)	0.0464 (0.0081)
Dummytran	-1414 (366)	-1452 (275)
Adjusted R-sq	0.76	-
Log likelihood	-	-68.9
Durbin-Watson	3.19	2.43
Estimated Auto	-0.59	-0.22

The OLS industrial distribution sales equation for Model 1 has a poor fit with an adjusted R-squared values of 0.11, although the Durbin-Watson statistic is close to 2.0. The maximum likelihood equation for distribution sales again looks reasonable. The maximum likelihood equation has a Durbin-Watson statistic that is better (very close to the desired value of 2.0) suggesting that auto-correlation has been reduced. According to this model, a one billion dollar increase in provincial GDP increases the industrial distribution voltage transmission demand for electricity by 7 MWh.

Table A7.3. Econometric Model of Industrial Distribution Sales (Model 1)

Variable	OLS	ML
Constant	2995 (513)	2956 (476)
GDP	0.0069(0.0043)	0.0073 (0.0040)
Dummydist	-	-
Adjusted R-sq	0.15	-
Log likelihood	-	-59.9
Durbin-Watson	2.21	2.10
Estimated Auto	-0.11	-0.05

The OLS industrial distribution sales equation for Model 2 has a good fit with an adjusted R-squared values of 0.68, although the Durbin-Watson statistic suggests the presence of auto-correlation. The maximum likelihood equation for distribution sales again looks reasonable. The maximum likelihood equation has a Durbin-Watson statistic that is much better (close to the desired value of

2.0) suggesting that auto-correlation has been reduced. According to this model, a one billion dollar increase in provincial GDP increases the industrial distribution voltage transmission demand for electricity by 12 MWh

Table A7.4. Econometric Model of Industrial Distribution Sales (Model 2)

Variable	OLS	ML
Constant	2697 (323)	2430 (116)
GDP	0.0097 (0.0028)	0.0121 (0.00099)
Rate		
Dummydist	-275 (72)	-339 (33)
Adjusted R-sq	0.68	-
Log likelihood	-	-49.4
Durbin-Watson	2.95	2.37
Estimated Auto	-0.48	-0.18

Appendix 8. Forecast Tables

Tables A8.1 and A8.2 summarize BC Hydro's reference load forecast including the effects of Power Smart and before Power Smart. Table A8.3 to A8.6 summarize BC Hydro's high and low scenarios resulting from the Monte Carlo uncertainty analysis including the effects of Power Smart and before Power Smart.

Table A8.1. 2004 BC Hydro, Reference Load Forecast Before Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,370	52,718	9,320
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,299	53,298	8,876	53,010	8,824
2003/04	15,899	14,151	18,725	48,775	1,185	49,960	313	50,273	4,914	55,187	10,159	54,892	10,103
Forecast													
2004/05	15,844	14,521	19,250	49,615	1,196	50,811	306	51,117	5,065	56,182	10,100	55,884	10,044
2005/06	16,220	14,731	19,473	50,424	1,127	51,551	311	51,862	5,111	56,973	10,192	56,673	10,136
2006/07	16,515	15,049	19,622	51,186	1,151	52,337	311	52,649	5,193	57,841	10,354	57,539	10,297
2007/08	16,880	15,316	19,773	51,969	1,207	53,176	313	53,488	5,280	58,769	10,509	58,462	10,451
2008/09	17,234	15,642	19,918	52,794	1,276	54,070	311	54,381	5,373	59,754	10,704	59,442	10,645
2009/10	17,601	15,983	19,612	53,196	1,295	54,491	311	54,802	5,433	60,235	10,831	59,917	10,771
2010/11	17,964	16,333	19,899	54,196	1,314	55,510	311	55,821	5,538	61,359	11,013	61,035	10,952
2011/12	18,326	16,581	19,711	54,618	1,334	55,952	313	56,265	5,597	61,862	11,114	61,532	11,052
2012/13	18,684	16,879	19,939	55,502	1,354	56,856	311	57,167	5,690	62,857	11,279	62,522	11,215
2013/14	19,033	17,156	20,176	56,365	1,375	57,740	311	58,051	5,780	63,831	11,425	63,491	11,360
2014/15	19,376	17,471	20,426	57,273	1,398	58,671	311	58,982	5,876	64,858	11,565	64,513	11,499
2015/16	19,715	17,777	20,682	58,174	1,419	59,593	313	59,906	5,970	65,876	11,722	65,525	11,655
2016/17	20,059	18,077	20,936	59,072	1,438	60,510	311	60,821	6,064	66,885	11,882	66,528	11,814
2017/18	20,405	18,382	21,193	59,980	1,456	61,436	311	61,747	6,159	67,906	12,049	67,543	11,979
2018/19	20,754	18,678	21,459	60,891	1,474	62,365	311	62,676	6,253	68,929	12,217	68,559	12,146
2019/20	21,100	19,022	21,729	61,851	1,490	63,341	313	63,654	6,354	70,008	12,386	69,632	12,314
2020/21	21,442	19,373	21,996	62,811	1,506	64,317	311	64,628	6,454	71,082	12,549	70,700	12,475
2021/22	21,785	19,731	22,268	63,784	1,523	65,307	311	65,618	6,555	72,173	12,711	71,785	12,636
2022/23	22,133	20,090	22,550	64,773	1,538	66,311	311	66,622	6,658	73,280	12,895	72,887	12,819
2023/24	22,481	20,461	22,830	65,772	1,553	67,325	313	67,638	6,762	74,400	13,082	74,001	13,004
2024/25	22,828	20,834	23,123	66,785	1,567	68,352	311	68,663	6,867	75,530	13,272	75,126	13,193
Growth Rates													
5 yrs 03/04-08/09	1.6%	2.0%	1.2%	1.6%	1.5%	1.6%	-0.1%	1.6%	1.6%	1.6%	1.1%	1.6%	1.1%
11 yrs 03/04-14/15	1.8%	1.9%	0.8%	1.5%	1.5%	1.5%	-0.1%	1.5%	1.6%	1.5%	1.2%	1.5%	1.2%
21 yrs 03/04-24/25	1.7%	1.9%	1.0%	1.5%	1.3%	1.5%	0.0%	1.5%	1.5%	1.5%	1.3%	1.5%	1.3%

Note: Losses are assumed to be 4% within the Distribution system and 7% within the Transmission system

Table A8.2. 2004 BC Hydro, Reference Load Forecast With Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,370	52,718	9,320
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,723	18,596	47,612	1,072	48,685	314	48,999	4,299	53,298	8,876	53,010	8,824
2003/04	15,899	14,151	18,725	48,775	1,185	49,960	313	50,273	4,914	55,187	10,159	54,892	10,103
Forecast													
2004/05	15,698	14,419	19,096	49,213	1,196	50,409	306	50,715	5,026	55,741	10,035	55,442	9,979
2005/06	15,999	14,588	18,927	49,514	1,127	50,641	311	50,952	5,030	55,982	10,052	55,682	9,996
2006/07	16,238	14,789	18,779	49,806	1,151	50,957	311	51,268	5,071	56,339	10,143	56,036	10,086
2007/08	16,543	14,908	18,569	50,020	1,207	51,227	313	51,540	5,108	56,648	10,213	56,342	10,155
2008/09	16,842	15,150	18,518	50,510	1,276	51,786	311	52,097	5,171	57,268	10,357	56,956	10,298
2009/10	17,161	15,457	18,150	50,768	1,295	52,063	311	52,374	5,217	57,591	10,461	57,273	10,401
2010/11	17,473	15,771	18,380	51,624	1,314	52,938	311	53,249	5,308	58,557	10,619	58,223	10,558
2011/12	17,778	15,989	18,114	51,881	1,334	53,215	313	53,528	5,352	58,880	10,694	58,550	10,632
2012/13	18,108	16,265	18,300	52,673	1,354	54,027	311	54,338	5,436	59,774	10,845	59,439	10,781
2013/14	18,460	16,528	18,532	53,520	1,375	54,895	311	55,206	5,525	60,731	10,988	60,391	10,923
2014/15	18,812	16,831	18,794	54,437	1,398	55,835	311	56,146	5,621	61,767	11,130	61,422	11,064
2015/16	19,160	17,138	19,087	55,385	1,419	56,804	313	57,117	5,719	62,836	11,294	62,485	11,227
2016/17	19,503	17,437	19,382	56,322	1,438	57,760	311	58,071	5,815	63,886	11,459	63,529	11,391
2017/18	19,850	17,734	19,663	57,247	1,456	58,703	311	59,014	5,911	64,925	11,628	64,562	11,558
2018/19	20,198	18,023	19,951	58,172	1,474	59,646	311	59,957	6,006	65,963	11,799	65,593	11,728
2019/20	20,545	18,363	20,265	59,173	1,490	60,663	313	60,976	6,109	67,085	11,973	66,709	11,901
2020/21	20,886	18,732	20,649	60,267	1,506	61,773	311	62,084	6,219	68,303	12,155	67,921	12,081
2021/22	21,229	19,117	21,055	61,401	1,523	62,924	311	63,235	6,333	69,568	12,340	69,180	12,265
2022/23	21,577	19,473	21,335	62,385	1,538	63,923	311	64,234	6,435	70,669	12,524	70,276	12,448
2023/24	21,925	19,844	21,620	63,389	1,553	64,942	313	65,255	6,540	71,795	12,711	71,396	12,633
2024/25	22,273	20,217	21,910	64,400	1,567	65,967	311	66,278	6,645	72,923	12,901	72,519	12,822
Growth Rates													
5 yrs 03/04-08/09	1.2%	1.4%	-0.2%	0.7%	1.5%	0.7%	-0.1%	0.7%	1.0%	0.7%	0.4%	0.7%	0.4%
11 yrs 03/04-14/15	1.5%	1.6%	0.0%	1.0%	1.5%	1.0%	-0.1%	1.0%	1.2%	1.0%	0.8%	1.0%	0.8%
21 yrs 03/04-24/25	1.6%	1.7%	0.8%	1.3%	1.3%	1.3%	0.0%	1.3%	1.4%	1.3%	1.1%	1.3%	1.1%

Note: Losses are assumed to be 4% within the Distribution system and 7% within the Transmission system

Table A8.3. 2004 BC Hydro, High Load Forecast Before Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,370	52,718	9,320
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,299	53,298	8,876	53,010	8,824
2003/04	15,899	14,151	18,725	48,775	1,185	49,960	313	50,273	4,914	55,187	10,159	54,892	10,103
Forecast													
2004/05	15,983	14,561	19,361	49,905	1,196	51,101	306	51,407	5,060	56,467	10,145	56,162	10,088
2005/06	16,429	14,827	19,677	50,933	1,127	52,060	311	52,371	5,161	57,532	10,292	57,223	10,234
2006/07	16,789	15,226	19,900	51,915	1,151	53,066	311	53,377	5,266	58,643	10,498	58,329	10,439
2007/08	17,217	15,578	20,115	52,910	1,207	54,117	313	54,430	5,374	59,804	10,694	59,485	10,634
2008/09	17,648	15,988	20,340	53,976	1,276	55,252	311	55,563	5,491	61,054	10,936	60,729	10,875
2009/10	18,081	16,416	20,104	54,601	1,295	55,896	311	56,207	5,574	61,781	11,108	61,450	11,046
2010/11	18,510	16,852	20,460	55,822	1,314	57,136	311	57,447	5,701	63,148	11,335	62,811	11,271
2011/12	18,940	17,180	20,326	56,446	1,334	57,780	313	58,093	5,781	63,874	11,476	63,530	11,411
2012/13	19,368	17,570	20,626	57,564	1,354	58,918	311	59,229	5,898	65,127	11,686	64,778	11,620
2013/14	19,776	17,933	20,934	58,643	1,375	60,018	311	60,329	6,011	66,340	11,873	65,985	11,806
2014/15	20,192	18,343	21,290	59,825	1,398	61,223	311	61,534	6,133	67,667	12,065	67,307	11,997
2015/16	20,597	18,730	21,630	60,957	1,419	62,376	313	62,689	6,251	68,940	12,267	68,574	12,197
2016/17	21,014	19,111	21,978	62,103	1,438	63,541	311	63,852	6,369	70,221	12,475	69,849	12,404
2017/18	21,444	19,513	22,341	63,298	1,456	64,754	311	65,065	6,493	71,558	12,696	71,179	12,624
2018/19	21,886	19,903	22,707	64,496	1,474	65,970	311	66,281	6,616	72,897	12,920	72,511	12,846
2019/20	22,306	20,339	23,071	65,716	1,490	67,206	313	67,519	6,743	74,262	13,138	73,870	13,063
2020/21	22,727	20,787	23,432	66,946	1,506	68,452	311	68,763	6,870	75,633	13,352	75,235	13,275
2021/22	23,171	21,262	23,826	68,259	1,523	69,782	311	70,093	7,006	77,099	13,578	76,694	13,500
2022/23	23,606	21,715	24,224	69,545	1,538	71,083	311	71,394	7,138	78,532	13,819	78,121	13,740
2023/24	24,040	22,212	24,618	70,870	1,553	72,423	313	72,736	7,275	80,011	14,068	79,595	13,987
2024/25	24,469	22,682	25,024	72,175	1,567	73,742	311	74,053	7,409	81,462	14,314	81,040	14,232
Growth Rates													
5 yrs 03/04-08/09	2.1%	2.5%	1.7%	2.0%	1.5%	2.0%	-0.1%	2.0%	2.2%	2.0%	1.5%	2.0%	1.5%
11 yrs 03/04-14/15	2.2%	2.4%	1.2%	1.9%	1.5%	1.9%	-0.1%	1.9%	2.0%	1.9%	1.6%	1.9%	1.6%
21 yrs 03/04-24/25	2.1%	2.3%	1.4%	1.9%	1.3%	1.9%	0.0%	1.9%	2.0%	1.9%	1.6%	1.9%	1.6%

Note: Losses are assumed to be 4% within the Distribution system and 7% within the Transmission system

Table A8.4. 2004 BC Hydro, Low Load Forecast Before Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,370	52,718	9,320
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,299	53,298	8,876	53,010	8,824
2003/04	15,899	14,151	18,725	48,775	1,185	49,960	313	50,273	4,914	55,187	10,159	54,892	10,103
Forecast													
2004/05	15,702	14,482	19,141	49,325	1,196	50,521	306	50,827	5,002	55,829	10,029	55,545	9,976
2005/06	16,009	14,634	19,268	49,911	1,127	51,038	311	51,349	5,060	56,409	10,091	56,125	10,038
2006/07	16,241	14,880	19,338	50,459	1,151	51,610	311	51,921	5,121	57,042	10,210	56,757	10,157
2007/08	16,544	15,062	19,410	51,016	1,207	52,223	313	52,536	5,185	57,721	10,321	57,435	10,267
2008/09	16,836	15,302	19,477	51,615	1,276	52,891	311	53,202	5,255	58,457	10,471	58,166	10,416
2009/10	17,136	15,554	19,107	51,797	1,295	53,092	311	53,403	5,293	58,696	10,554	58,399	10,498
2010/11	17,441	15,825	19,316	52,582	1,314	53,896	311	54,207	5,376	59,583	10,694	59,281	10,637
2011/12	17,741	15,991	19,065	52,797	1,334	54,131	313	54,444	5,414	59,858	10,754	59,550	10,696
2012/13	18,031	16,209	19,208	53,448	1,354	54,802	311	55,113	5,484	60,597	10,873	60,284	10,814
2013/14	18,314	16,402	19,377	54,093	1,375	55,468	311	55,779	5,552	61,331	10,977	61,013	10,917
2014/15	18,598	16,629	19,545	54,772	1,398	56,170	311	56,481	5,625	62,106	11,074	61,784	11,013
2015/16	18,871	16,853	19,712	55,436	1,419	56,855	313	57,168	5,695	62,863	11,185	62,535	11,123
2016/17	19,156	17,073	19,888	56,117	1,438	57,555	311	57,866	5,767	63,633	11,305	63,300	11,241
2017/18	19,436	17,303	20,050	56,789	1,456	58,245	311	58,556	5,839	64,395	11,426	64,056	11,361
2018/19	19,705	17,518	20,220	57,443	1,474	58,917	311	59,228	5,908	65,136	11,544	64,791	11,478
2019/20	19,991	17,775	20,387	58,153	1,490	59,643	313	59,956	5,983	65,939	11,666	65,588	11,599
2020/21	20,252	18,037	20,561	58,850	1,506	60,356	311	60,667	6,057	66,724	11,779	66,368	11,710
2021/22	20,523	18,301	20,737	59,561	1,523	61,084	311	61,395	6,132	67,527	11,893	67,165	11,823
2022/23	20,794	18,574	20,914	60,282	1,538	61,820	311	62,131	6,208	68,339	12,026	67,972	11,955
2023/24	21,056	18,856	21,102	61,014	1,553	62,567	313	62,880	6,286	69,166	12,161	68,794	12,089
2024/25	21,326	19,150	21,274	61,750	1,567	63,317	311	63,628	6,364	69,992	12,298	69,615	12,225
Growth Rates													
5 yrs 03/04-08/09	1.2%	1.6%	0.8%	1.1%	1.5%	1.1%	-0.1%	1.1%	1.4%	1.2%	0.6%	1.2%	0.6%
11 yrs 03/04-14/15	1.4%	1.5%	0.4%	1.1%	1.5%	1.1%	-0.1%	1.1%	1.2%	1.1%	0.8%	1.1%	0.8%
21 yrs 03/04-24/25	1.4%	1.5%	0.6%	1.1%	1.3%	1.1%	0.0%	1.1%	1.2%	1.1%	0.9%	1.1%	0.9%

Note: Losses are assumed to be 4% within the Distribution system and 7% within the Transmission system

Table A8.5. 2004 BC Hydro, High Load Forecast With Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,370	52,718	9,320
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,299	53,298	8,876	53,010	8,824
2003/04	15,899	14,151	18,725	48,775	1,185	49,960	313	50,273	4,914	55,187	10,159	54,892	10,103
Forecast													
2004/05	15,836	14,459	19,209	49,504	1,196	50,700	306	51,006	5,020	56,026	10,151	55,721	10,094
2005/06	16,208	14,686	19,129	50,023	1,127	51,150	311	51,461	5,080	56,541	10,294	56,232	10,236
2006/07	16,512	14,966	19,055	50,533	1,151	51,684	311	51,995	5,144	57,139	10,501	56,825	10,442
2007/08	16,880	15,170	18,914	50,964	1,207	52,171	313	52,484	5,203	57,687	10,701	57,368	10,641
2008/09	17,256	15,494	18,940	51,690	1,276	52,966	311	53,277	5,289	58,566	10,946	58,241	10,885
2009/10	17,641	15,892	18,643	52,176	1,295	53,471	311	53,782	5,359	59,141	11,122	58,810	11,060
2010/11	18,019	16,292	18,939	53,250	1,314	54,564	311	54,875	5,472	60,347	11,350	60,010	11,286
2011/12	18,392	16,587	18,730	53,709	1,334	55,043	313	55,356	5,536	60,892	11,494	60,548	11,429
2012/13	18,791	16,954	18,985	54,730	1,354	56,084	311	56,395	5,644	62,039	11,706	61,690	11,640
2013/14	19,203	17,305	19,291	55,799	1,375	57,174	311	57,485	5,755	63,240	11,896	62,885	11,829
2014/15	19,628	17,703	19,659	56,990	1,398	58,388	311	58,699	5,878	64,577	12,090	64,217	12,022
2015/16	20,041	18,090	20,035	58,166	1,419	59,585	313	59,898	5,999	65,897	12,293	65,531	12,223
2016/17	20,458	18,470	20,424	59,352	1,438	60,790	311	61,101	6,120	67,221	12,502	66,849	12,431
2017/18	20,888	18,867	20,809	60,564	1,456	62,020	311	62,331	6,245	68,576	12,725	68,197	12,653
2018/19	21,330	19,246	21,199	61,775	1,474	63,249	311	63,560	6,369	69,929	12,951	69,543	12,877
2019/20	21,750	19,681	21,607	63,038	1,490	64,528	313	64,841	6,498	71,339	13,171	70,947	13,096
2020/21	22,171	20,146	22,085	64,402	1,506	65,908	311	66,219	6,635	72,854	13,385	72,456	13,308
2021/22	22,615	20,644	22,614	65,873	1,523	67,396	311	67,707	6,783	74,490	13,610	74,085	13,532
2022/23	23,050	21,096	23,011	67,157	1,538	68,695	311	69,006	6,915	75,921	13,853	75,510	13,774
2023/24	23,484	21,593	23,406	68,483	1,553	70,036	313	70,349	7,052	77,401	14,103	76,985	14,022
2024/25	23,913	22,063	23,812	69,788	1,567	71,355	311	71,666	7,186	78,852	14,350	78,430	14,268
Growth Rates													
5 yrs 03/04-08/09	1.7%	1.8%	0.2%	1.2%	1.5%	1.2%	-0.1%	1.2%	1.5%	1.2%	1.5%	1.2%	1.5%
11 yrs 03/04-14/15	1.9%	2.1%	0.4%	1.4%	1.5%	1.4%	-0.1%	1.4%	1.6%	1.4%	1.6%	1.4%	1.6%
21 yrs 03/04-24/25	2.0%	2.1%	1.2%	1.7%	1.3%	1.7%	0.0%	1.7%	1.8%	1.7%	1.7%	1.7%	1.7%

Note: Losses are assumed to be 4% within the Distribution system and 7% within the Transmission system

Table A8.6. 2004 BC Hydro, Low Load Forecast With Power Smart

	BC Hydro Service Area Sales											Integrated System	
	Residential	Commercial	Industrial	Total BCH	New West Aquila	Total Domestic Sales	Firm Export	Total Firm Sales	Losses	Total Gross Require-ments	Total System Peak	Total Gross Require-ments	Peak
	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(GWh)	(MW)	(GWh)	(MW)
Actual													
1999/00	14,572	13,176	17,890	45,639	738	46,376	314	46,691	4,843	51,534	8,694	51,279	8,646
2000/01	14,573	13,654	18,579	46,805	1,085	47,891	314	48,204	4,774	52,978	9,370	52,718	9,320
2001/02	15,090	13,583	17,739	46,412	1,062	47,473	314	47,787	4,780	52,567	9,054	52,292	9,003
2002/03	15,287	13,729	18,596	47,612	1,072	48,685	314	48,999	4,299	53,298	8,876	53,010	8,824
2003/04	15,899	14,151	18,725	48,775	1,185	49,960	313	50,273	4,914	55,187	10,159	54,892	10,103
Forecast													
2004/05	15,555	14,380	18,989	48,924	1,196	50,120	306	50,426	4,962	55,388	10,036	55,104	9,983
2005/06	15,788	14,493	18,720	49,001	1,127	50,128	311	50,439	4,979	55,418	10,089	55,134	10,036
2006/07	15,964	14,620	18,493	49,077	1,151	50,228	311	50,539	4,999	55,538	10,206	55,253	10,153
2007/08	16,207	14,654	18,209	49,070	1,207	50,277	313	50,590	5,014	55,604	10,315	55,318	10,261
2008/09	16,444	14,808	18,077	49,329	1,276	50,605	311	50,916	5,053	55,969	10,461	55,678	10,406
2009/10	16,696	15,030	17,646	49,372	1,295	50,667	311	50,978	5,078	56,056	10,542	55,759	10,486
2010/11	16,950	15,265	17,795	50,010	1,314	51,324	311	51,635	5,147	56,782	10,679	56,480	10,622
2011/12	17,193	15,398	17,469	50,060	1,334	51,394	313	51,707	5,169	56,876	10,736	56,568	10,678
2012/13	17,454	15,593	17,567	50,614	1,354	51,968	311	52,279	5,230	57,509	10,851	57,196	10,792
2013/14	17,741	15,774	17,734	51,249	1,375	52,624	311	52,935	5,297	58,232	10,954	57,914	10,894
2014/15	18,034	15,989	17,914	51,937	1,398	53,335	311	53,646	5,370	59,016	11,049	58,694	10,988
2015/16	18,315	16,213	18,117	52,645	1,419	54,064	313	54,377	5,444	59,821	11,159	59,493	11,097
2016/17	18,600	16,432	18,334	53,366	1,438	54,804	311	55,115	5,518	60,633	11,277	60,300	11,213
2017/18	18,880	16,657	18,518	54,055	1,456	55,511	311	55,822	5,590	61,412	11,397	61,073	11,332
2018/19	19,149	16,861	18,712	54,722	1,474	56,196	311	56,507	5,660	62,167	11,514	61,822	11,448
2019/20	19,435	17,117	18,923	55,475	1,490	56,965	313	57,278	5,738	63,016	11,635	62,665	11,568
2020/21	19,696	17,396	19,214	56,306	1,506	57,812	311	58,123	5,822	63,945	11,748	63,589	11,679
2021/22	19,967	17,683	19,525	57,175	1,523	58,698	311	59,009	5,909	64,918	11,861	64,556	11,791
2022/23	20,238	17,955	19,701	57,894	1,538	59,432	311	59,743	5,985	65,728	11,993	65,361	11,922
2023/24	20,500	18,237	19,890	58,627	1,553	60,180	313	60,493	6,063	66,556	12,127	66,184	12,055
2024/25	20,770	18,531	20,062	59,363	1,567	60,930	311	61,241	6,141	67,382	12,263	67,005	12,190
Growth Rates													
5 yrs 03/04-08/09	0.7%	0.9%	-0.7%	0.2%	1.5%	0.3%	-0.1%	0.3%	0.6%	0.3%	0.6%	0.3%	0.6%
11 yrs 03/04-14/15	1.2%	1.1%	-0.4%	0.6%	1.5%	0.6%	-0.1%	0.6%	0.8%	0.6%	0.8%	0.6%	0.8%
21 yrs 03/04-24/25	1.3%	1.3%	0.3%	0.9%	1.3%	0.9%	0.0%	0.9%	1.1%	1.0%	0.9%	1.0%	0.9%

Note: Losses are assumed to be 4% within the Distribution system and 7% within the Transmission system